4 Petroleum Diesel Fuel Modeling

This section describes each phase of the life cycle for petroleum diesel. Data and assumptions used in this life cycle are based on the current U.S. petroleum industry.

- ***4.1 Petroleum Diesel Fuel General Modeling Assumptions:*** This section outlines the boundaries of this study (i.e., which data are included and omitted). This refers to physical geographic boundary assumptions as well as to the exclusion of secondary sources of data such as the production of capital equipment.
- ***4.2 Crude Oil Extraction:*** This section describes the process flows associated with crude oil extraction from the ground and subsequent upgrading before transportation. This section explains the assumptions that went into modeling these processes.
- ***4.3 Crude Oil Transport to Refinery:*** This section explains how transportation is regionalized by the five PADDs. It also explains how transportation distances were calculated and describes the various transportation models used to depict the transport of crude oil.
- ***4.4 Crude Oil Refining:*** This section details the assumptions concerning refinery operations, including allocation principles and methodologies used to designate total refinery process flows specifically to diesel fuel.
- ***4.5: Diesel Fuel Transport:*** This section defines how diesel is stored and transported to point of use. The final point-of-use locations are described in section 2 of this report.

4.1 Petroleum Diesel Fuel General Modeling Assumptions

4.1.1 Geographic Boundaries

The modeling of petroleum-based diesel fuel production includes worldwide crude oil extraction but not foreign refinery operations or transport of foreign intermediate refinery products or diesel fuel to the United States. Foreign crude oil extraction and transportation to the United States is modeled because half the U.S. supply of crude oil is imported. Total crude oil input to U.S. refineries has been slowly rising over the past decade, and has exceeded 50% of U.S. consumption since 1994 (Figure 28) (EIA Historical Monthly Energy Review 1973 - 1992 & EIA, 1995a).

Foreign diesel fuel production and transportation are not included in this study because diesel fuel imports represent only 4% of the total diesel fuel used in the United States (EIA 1995a). In addition, imports of intermediate refinery products (products used in the production of diesel fuel, such as Fischer-Tropsch diesel) are also small (approximately 3% of total U.S. use) and are not included in this analysis (EIA 1995a).

Imported crude oil comes from all parts of the world, and limited data are available on foreign crude oil extraction techniques, input requirements, and characteristics. The lack of data makes it difficult to model foreign crude oil extraction and upgrading before transportation. Therefore, U.S. production data are sometimes used to estimate foreign crude oil production parameters, even though such data may not accurately reflect foreign oil production characteristics. Given the size of the crude oil contribution to U.S. refinery inputs, this approach was considered the most cost effective.

Figure 29 outlines the petroleum industry process areas that are considered in this project.

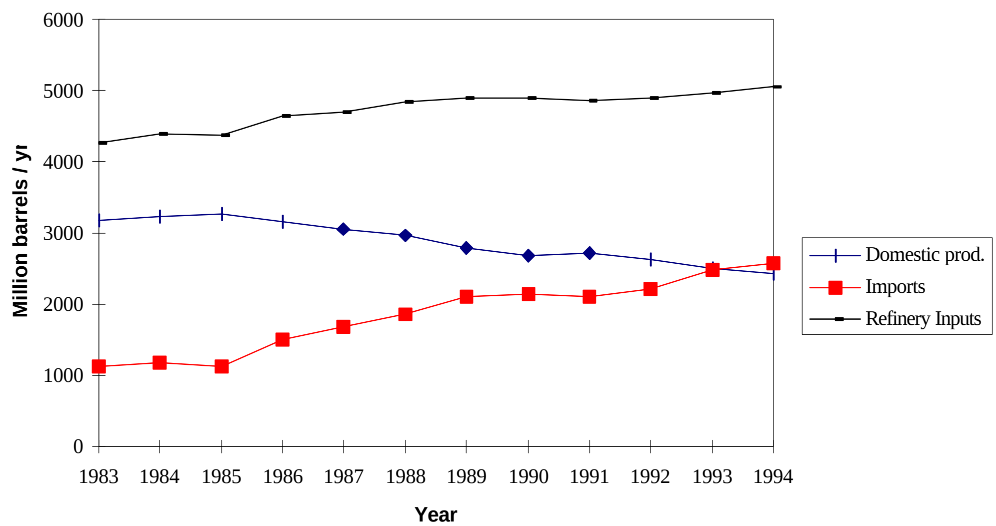

Figure 28: U.S. Crude Oil Production, Imports and Input to Refineries (1983-1994)

4.2 Crude Oil Extraction

Three separate types of processes for extracting crude oil are modeled in the petroleum extraction system, all based on a recent life cycle study of U.S. petroleum production processes (Tyson et al. 1993). The three processes are onshore production, offshore production, and enhanced recovery. Enhanced recovery entails the underground injection of steam (produced by natural gas boilers) and CO_2 to force the crude oil to the surface. The shares of total crude oil recovered by each process, for domestic and foreign production, are shown in Table 18[24].

Within the enhanced/advanced crude oil extraction category, two processes are typically used with different energy and material requirements: steam injection and CO_2 injection. Steam injection is assumed to account for 63% of the enhanced/advanced extraction, and CO_2 injection is assumed to account for the remaining 37%. Each of these production types will be considered in more detail in the following sections.

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[24] Source: Shares of each production type were obtained from the Oil & Gas Journal Database, using numbers obtained in 1994. The Enhanced/Advanced category includes all advanced crude oil extraction techniques except water flooding. It is assumed that steam flooding and CO_2 injection will represent the largest portion of the Enhanced/Advanced techniques obtained from the Oil & Gas Journal Database.

Table 18: Production of Crude Oil by Technology Type and Origin

Technology Type	Domestic Crude Oil Production	Foreign Crude Oil Production
Conventional Onshore	69%	77%
Conventional Offshore	20%	20%
Enhanced/Advanced	11%	3%

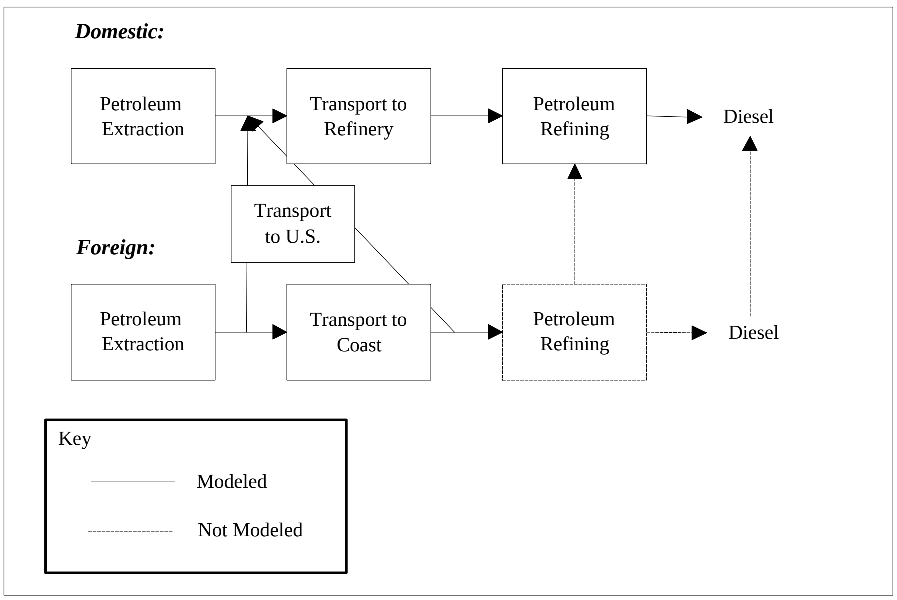

Figure 29: Petroleum Process Areas Modeled in this Project

4.2.1 Conventional Onshore Extraction

Figure 30 shows the system process diagram associated with conventional onshore crude oil extraction. It demonstrates the system boundaries and process flows modeled for conventional onshore crude oil extraction in this study.

4.2.1.1 Material Use

The only raw material inputs required for conventional onshore crude oil extraction accounted for in this study are the actual crude oil and natural gas in the ground. We assumed that there is no loss of crude oil once it is extracted from the well.

The life cycle environmental flows associated with producing capital equipment and the facilities used to extract crude oil are excluded from this study. However, the energy required for drilling and exploration are included. The energy required to explore and drill for conventional onshore crude oil represents approximately 0.75% of the energy contained in the oil produced (Delucchi 1993). This energy is primarily used for drilling, and is accounted for by increasing the amount of crude oil in the ground needed to produce 1 kg of crude oil. Therefore, conventional onshore crude oil extraction requires 1.0075 kg of crude oil in the ground to produce 1 kg of crude oil. The material requirements for both domestic and foreign conventional onshore crude oil extraction are assumed to be the same.

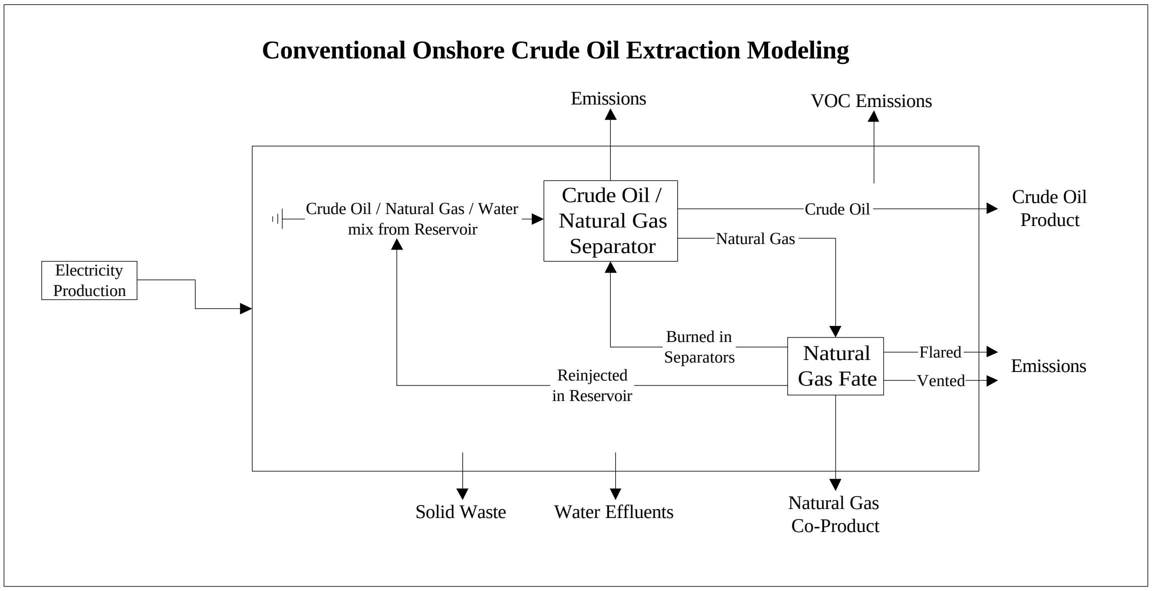

Figure 30: Conventional Onshore Crude Oil Extraction

4.2.1.2 Energy/Equipment Use

Energy requirements for both domestic and foreign conventional onshore crude oil production are based on a 400-well production field (195 unproductive wells) located in the lower 48 states producing 4.98 x 10^9 kg/yr (3.65 x 10^7 bbl/yr) of crude oil (DOE 1983) as follows:

Electricity:	10.7 kWh/bbl	(used in pumping)
Natural Gas:	5.2 MJ/bbl	(used in recovery)

Electricity is assumed to come from a generic (national average) U.S. grid; natural gas is assumed to come from gross production of the well. The national average grid was used because our modeling of crude oil production is generic to the U.S., and is not broken down regionally. The LCI model converts all secondary energy inputs, such as electricity, into their primary or original raw energy inputs for reporting purposes[25].

The electricity used in foreign crude oil extraction was based on the standard U.S. grid, even though it is not an accurate representation of the foreign electricity used in foreign oil fields. This assumption was necessary because of the lack of data describing foreign electricity production and its use in foreign oil extraction[26]. This assumption will result in conservative estimates of electricity use impacts because

[25] Fuels can be divided into two groups: primary and secondary. Primary fuels are those, such as coal, oil, and gas, which are directly extracted from the earth and liberate energy when burned. Secondary fuels are those such as electricity, coke, and manufactured gas, which are produced from primary fuels. This conversion is based on modeled secondary energy sectors in the Ecobalance database DEAM™

[26] Actually, each U.S. crude oil production field would have its own mix of electricity use. However, the standard U.S. grid was used to represent an average situation.

foreign electricity production sources may not meet the same strict emission guidelines as those in the United States.

4.2.1.3 Process Emissions

Air, water, and solid waste emissions are emitted from conventional onshore crude oil extraction.

Water effluents are based on the amount of wastewater produced and its estimated average composition. The EPA (1997) estimated that 0.7 L of wastewater are produced for every kg of crude oil produced by conventional onshore crude oil extraction.). The total wastewater produced is actually higher than this estimate, but only 0.7 L are released to the environment. The rest is treated on site through reinjection, evaporation, etc. The compositions of the wastewater contaminants are shown in Table 19 (EPA 1987). In addition to those contaminants shown by the EPA, DOE (1983) estimated total oil and grease contained in the wastewater released to be 1×10^{-4} kg/kg crude oil produced.

Table 19: Crude Oil Production Wastewater Constituents and Concentrations

Constituent	Median Concentration (mg/L)
Arsenic	0.02
Benzene	0.47
Boron	9.9
Sodium	9,400
Chloride	7,300
Mobile ions	23,000

The emission factor for the production of solid waste is calculated as 0.0098 of solid waste are produced for every kg of crude oil (Tyson et al., 1993).

Air emissions from conventional onshore crude oil extraction come from the combustion of natural gas in the crude oil/natural gas separators, venting and flaring of natural gas, and from volatilization (fugitive) emissions of crude oil.

The emission factors for natural gas combustion of the crude oil/natural gas separators were assumed to be the same as industrial boilers (shown in Appendix A). This may be conservative because many of these burners are located in remote sites where requirements for emissions may be less stringent.

Natural gas venting/flaring emissions from crude oil extraction have been calculated based on a percentage of the gross natural gas production of the well based on the following data and assumptions. DOE estimates of the gross extraction of associated natural gas from crude oil wells in the United States (EIA Natural Gas Annual 1994) were divided by the amount of crude oil produced in 1994 (EIA Petroleum Supply Annual 1997). The resulting estimate, 0.47 kg of associated natural gas produced per kg of crude oil produced, was used to characterize domestic and foreign crude oil wells.

DOE then estimated the amount of natural gas vented and flared for natural gas extraction (EIA Natural Gas Annual 1994). We assumed the percentage of natural gas flared and vented is the same for total natural gas as for associated natural gas from crude oil wells because the authors did not distinguish between these two sources. For foreign venting and flaring practices, DOE estimated the amount of natural gas flared and vented in 1994 (EIA International Energy Annual 1995). Once again, the percentage of natural gas flared and vented is assumed to be the same for total natural gas as for natural gas from crude oil wells. Based on previous research by DeLucchi (1993) we assumed that 97.5% of the total amount of natural gas vented and flared was actually flared; only 2.5% is vented. Table 20 shows the net result of these assumptions and calculations for natural gas venting and flaring from conventional onshore crude oil extraction.

Based on the amount of gas produced, these proportions can be used to estimate a constant factor for kg of natural gas flared and vented per kg of crude oil extracted. In this study, 0.0057 kg of natural gas is flared and 0.00014 kg of natural gas is vented per kg of domestic onshore crude oil extracted.

Table 20: Natural Gas Venting and Flaring from Onshore Crude Oil Wells

	Conventional Onshore Extraction
Gross Natural Gas extracted (kg/kg crude)	0.47
Domestic % Flared	1.22%
Domestic % Vented	0.03%
Foreign % Flared	4.53%
Foreign % Vented	0.12%

The amount of foreign natural gas flared and vented per kg of crude oil extracted is calculated in a similar manner, resulting in an assumption of 0.021 kg of natural gas flared and 0.00056 kg of natural gas vented per kg of foreign onshore crude oil extracted.

The amount that is vented is assumed to be released as CH_4, although it is well known that the actual gas contains numerous other constituents of varying proportions. Data reflecting national averages of these constituents could be not found. The emissions from the amount that is flared are based on the emission factors for industrial flares shown in Appendix A.

The EPA provided estimates of volatile organic compound (VOC) emissions from onshore crude oil extraction (shown in Table 21) (EPA 1990). The EPA also provided some speciated estimates of the gross emissions (shown in Table 22). In 1994 the average productivity of U.S. crude oil production wells was 1,555 kg of crude oil/day per well (11.4 bbl/day per well) (EIA 1995b). Using this estimate, VOC emissions data were converted into kg of speciated VOCs per kg of crude oil produced and used in subsequent modeling.

4.2.1.4 Crude Oil Separation

The extracted crude oil must undergo an additional step before it is ready to be shipped to refineries; it must be separated from the natural gas and water. These field separators are assumed to operate on natural gas produced at the site, as explained in the previous sections. The combustion of natural gas leads to air emissions, which are based on emissions from industrial boilers described in Appendix A.

Table 21: VOC Emissions for Onshore Crude Oil Wells

Component	Emission Factor (g/well-yr.)
Fugitive Emissions	180,000
Crude Oil Sumps	4,000
Crude Oil Pits	4,000
Total	188,000

Table 22: Speciated VOC Data for Onshore Crude Oil Wells

Compound	Wt %
Isomers of Hexane	9.9
Isomers of Heptane	11.6
Isomers of Octane	8.7
C-7 Cycloparaffins	1.6
C-8 Cycloparaffins	0.6
Isomers of Pentane	5.6
Methane	38.0
Ethane	6.4
Propane	10.0
n-Butane	7.4
iso-Butane	0.4
Benzene	0.1

4.2.1.5 Crude Oil and Natural Gas Allocations – Conventional Onshore

Because associated natural gas is a coproduct of crude oil production, the emissions associated with the crude oil extraction and separation need to be allocated between crude oil and natural gas production. In order to arrive at a reasonable allocation methodology, the natural gas that is reinjected, flared, and vented must be taken into account because only the natural gas that is transported offsite is considered a coproduct. The onsite uses of natural gas must be netted out of the total gross natural gas produced.

According to DOE, 17.8% of the associated natural gas produced in 1994 was reinjected during onshore crude oil extraction (EIA Natural Gas Annual 1994). An estimated 9.98% of the associated natural gas extracted during foreign crude oil recovery was reinjected (EIA International Energy Annual 1995). This fraction was assumed to reflect practices of onshore and offshore crude oil recovery because the data did not reflect production technology characteristics.

The fraction of associated natural gas produced that is flared and vented during domestic and foreign conventional crude oil recovery was discussed in a previous section, and is reproduced in Table 23. Using the previous assumption that 0.47 kg of natural gas is extracted for every kg of crude oil extracted, the calculation of the amount of natural gas produced as a coproduct is shown in Table 23.

Using these raw estimates of the mass of natural gas and crude oil produced, mass allocation ratios can be calculated for domestic (Table 24) and foreign (Table 25) conventional onshore crude oil extraction. These ratios are used to allocate the inputs and emissions associated with crude oil extraction between the crude oil and the associated natural gas produced. For example, 72% of the emissions from flaring and venting, operating separators, fugitive emissions, and raw materials and energy consumed during conventional onshore crude oil extraction are assigned to the crude oil produced; the remaining 28% are assigned to the coproduct natural gas.

Table 23: Natural Gas Venting, Flaring, and Coproduct Production from Onshore Crude Oil Wells

	Onshore Extraction
Gross NG extracted (kg/kg crude)	0.47
Domestic % Reinjected	17.8 %
Domestic % Flared/Vented	1.25 %
Foreign % Reinjected	9.98 %
Foreign % Flared/Vented	4.65 %
Co-Product Domestic	80.95 % x 0.47 = 0.38 kg
Co-Product Foreign	85.37 % x 0.47 = 0.40 kg

Table 24: Production of Typical Domestic Conventional Onshore Crude Oil Well

	Mass (kg)	Mass (%)
Crude Oil	1	72 %
Natural Gas	0.38	28 %
Total	1.38	

Table 25: Production of Typical Foreign Conventional Onshore Crude Oil Well

	Mass (kg)	Mass (%)
Crude Oil	1	71 %
Natural Gas	0.40	29 %
Total	1.40	

4.2.2 Conventional Offshore Extraction

Figure 31 shows the system process diagram associated with conventional offshore crude oil extraction. It demonstrates the system boundaries and process flows modeled for conventional offshore crude oil extraction in this study.

4.2.2.1 Material Use

The only raw material inputs required for conventional offshore crude oil extraction accounted for in this study, is the actual crude oil and natural gas in the ground. We assumed that there is no loss of crude oil once it is extracted from the well.

The life cycle environmental flows associated with producing capital equipment and the facilities for extracting crude oil are excluded from this study. However, the energy required for drilling and exploration are included. For conventional offshore crude oil production, exploration, and drilling energy represents approximately 7%-8% of the energy in the produced crude oil (DeLucchi 1993). The average, or 7.5%, is used in this study. This energy is primarily used for drilling. This energy is accounted for by increasing the amount of crude oil in the ground needed to produce 1 kg of crude oil. Therefore, conventional offshore crude oil extraction would require 1.075 kg of crude oil in the ground to produce 1 kg of crude oil. The material requirements for domestic and foreign conventional offshore crude oil extraction are assumed to be the same.

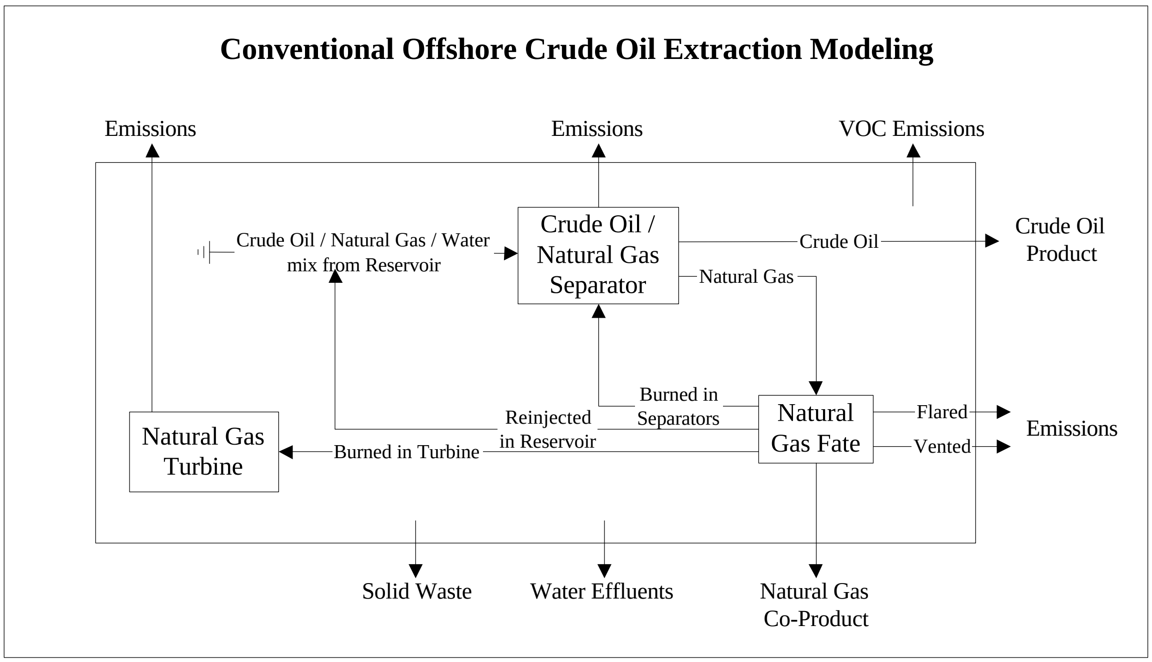

Figure 31: Conventional Offshore Crude Oil Extraction

4.2.2.2 Energy/Equipment Use

Energy used to extract crude oil is assumed to come from the gross production of the well. Energy requirements for both foreign and domestic conventional offshore crude oil production are based on an

18-well offshore platform producing 1.97 x 10^8 kg of crude oil/yr (1.46 x 10^6 bbl/yr) (DOE 1983) as follows[27]:

Natural Gas (used in recovery): 38.8 MJ/bbl

Natural Gas (used for electricity, pumping, etc.): 96.6 MJ/bbl

Unlike conventional onshore crude oil production, natural gas is used for the separators and for producing electricity for pumping and other uses.

4.2.2.3 Process Emissions

Air, water, and solid waste emissions are produced during conventional offshore crude oil extraction.

Water effluents are based on the amount of wastewater produced and its estimated average composition. The U.S. Department of Interior (DOI) estimates that 10.14 L of wastewater are released for every kg of crude oil produced (DOI 1991). All the wastewater produced is assumed to be released to the surrounding environment.

The EPA estimates of the wastewater constituents and concentrations are shown in Table 19 (EPA 1987). In addition, DOI estimates that 2.8 x 10^{-4} kg of oil and grease are included in the wastewater for every kg crude oil produced (DOI 1990).

The emission factor for the production of solid waste is calculated as 0.0098 g of solid waste generated for every kg of crude oil (Tyson et al. 1993).

Air emissions from conventional offshore crude oil extraction come from the combustion of natural gas in the crude oil/natural gas separators and natural gas turbine, venting, and flaring of natural gas as well as from volatilization (i.e., fugitive) emissions of crude oil.

The emission factors for natural gas combustion from operating the separators were assumed to be the same as industrial boilers. This may be conservative because many of these burners are located in remote sites where requirements for emissions may be less stringent. The emission factors for natural gas combustion used to produce electricity are based on natural gas emission factors from a gas turbine (shown in Appendix A).

Natural gas venting and flaring emissions from offshore crude oil extraction are calculated based on a percentage of the gross natural gas production of the well and a variety of assumptions shown in Table 26. DOE estimates of gross natural gas extracted from offshore wells (EIA Natural Gas Annual 1994) were divided by DOE estimates of gross crude oil production from offshore wells in 1994 (EIA Petroleum Supply Annual 1997) to arrive at an estimated 0.26 kg of associated natural gas produced for every kg of crude oil extracted from offshore oil wells. Lacking any information on foreign offshore associated natural gas production, U.S. offshore estimates were used for both.

DOE provides estimates of the total amount of natural gas vented and flared from offshore extraction activities (EIA Natural Gas Annual 1994). The percentage of natural gas flared and vented offshore is used to estimate the total amount of associated natural gas produced in offshore oil wells that is vented and flared. DOE estimates of foreign natural gas flaring and venting for 1994 do not distinguish between onshore and off, and the number provide is used for both activities. (EIA International Energy Annual 1995). Based on a previous assumption by Delucchi (1993), 75% of the associated natural gas produced offshore is assumed to be flared and 25% is assumed to be vented.

[27] Electrical energy requirements are assumed to be met through the use of natural gas turbines.

Table 26: Natural Gas Venting and Flaring from Offshore Crude Oil Wells

	Conventional Offshore Extraction
Gross Natural Gas Extracted (kg/kg crude)	0.26
Domestic % Flared	0.067%
Domestic % Vented	0.022%
Foreign % Flared	3.49%
Foreign % Vented	1.16%

The assumptions presented in Table 26 are used to calculate fixed factors of natural gas flaring and venting per kg of crude oil produced from offshore wells. Based on the total natural gas produced by the well, 0.00017 kg of natural gas is flared and 0.000057 kg of natural gas is vented per kg of domestic offshore crude oil extracted. Similarly, 0.0091 kg of foreign natural gas is flared and 0.0030 kg of foreign natural gas are vented per kg of foreign offshore crude oil extracted.

The amount that is vented is assumed to be released as CH_4, although the actual composition of the gases flared and vented is more complex. The emissions from the flared natural gas are based on the emission factors for industrial flares shown in Appendix A.

A study by Tyson et al. (1993) provides estimates of VOC emissions released during conventional offshore crude oil production (Table 27), which are used in this study.

Table 27: Speciated VOC Emissions for Offshore Crude Oil Production

Pollutant	Emission rate (kg/kg crude oil produced)
Methane	5.6×10^{-5}
Formaldehyde	1.9×10^{-5}
Isomers of Hexane	3.0×10^{-6}
Isomers of Heptane	2.3×10^{-5}
Isomers of Octane	2.6×10^{-6}
C-7 Cycloparaffins	3.2×10^{-6}
C-8 Cycloparaffins	1.2×10^{-6}
Isomers of Pentane	1.1×10^{-5}
Ethane	1.3×10^{-5}
Propane	2.0×10^{-5}
n-Butane	1.5×10^{-5}
iso-Butane	8.0×10^{-7}
Benzene	2.0×10^{-7}

4.2.2.4 Crude Oil Separation

Directly after extraction and before shipping the crude oil produced offshore, the crude oil is separated from the contained gases (natural gas), water, and wastes using field separators. These separators are assumed to be operated by burning some of the associated natural gas as explained in the previous sections. The combustion of this natural gas leads to air emissions, which are assumed to be similar to industrial boiler emissions.

4.2.2.5 Crude Oil and Natural Gas Allocations – Conventional Offshore

Because natural gas is a coproduct of crude oil production, the energy and emissions associated with its production need to be allocated between crude oil and natural gas production. To arrive at a reasonable allocation method, the natural gas that is reinjected, vented, and flared needs to be deducted from the total amount of associated natural gas produced. Only the natural gas that is transported from the offshore production facilities is considered a coproduct of the crude oil produced.

The amount of natural gas vented and flared during offshore production has already been discussed. The amount of natural gas reinjected during domestic offshore crude oil extraction is estimated at 2.46% (EIA Natural Gas Annual 1994). The previous estimate of reinjected natural gas for foreign crude oil production is used for offshore and onshore production, because the data did not distinguish between crude oil extraction activities.

Based on the data provided, 97.45% of the total natural gas extracted is considered a coproduct of domestic offshore crude oil production, and 85.37% of the foreign associated natural gas is considered a coproduct to foreign offshore crude oil production (Table 28). Applying these estimates to the mass of natural gas produced per kg of domestic (Table 29) and foreign (Table 30) offshore crude oil produced, yields the coproduct allocation ratios. These ratios are applied to the inputs and emissions associated with offshore crude oil production. For example, with conventional domestic offshore crude oil production, 80% of the total emissions, raw materials, and energy use are allocated to crude oil and 20% are allocated to the coproduct natural gas.

Table 28: Natural Gas Venting, Flaring, and Coproduct Production from Offshore Crude Oil Wells

	Offshore Extraction
Gross Natural Gas Extracted (kg/kg crude)	0.26
Domestic % Reinjected	2.46%
Domestic % Flared/Vented	0.089%
Foreign % Reinjected	9.98%
Foreign % Flared/Vented	4.65%
Coproduct Domestic	97.45% x 0.26 = 0.25 kg
Coproduct Foreign	85.37% x 0.26 = 0.22 kg

Table 29: Production of Typical Domestic Conventional Offshore Crude Oil Well

	Mass (kg)	Mass (%)
Crude Oil	1	80%
Natural Gas	0.25	20%
Total	1.25	

Table 30: Production of Typical Foreign Conventional Offshore Crude Oil Well

	Mass (kg)	Mass (%)
Crude Oil	1	82%
Natural Gas	0.22	18%
Total	1.22	

4.2.3 Advanced Onshore Extraction (Steam Injection)

Figure 32 shows the system process diagram associated with advanced onshore crude oil extraction through the use of steam injection. It demonstrates the system boundaries and process flows modeled for advanced steam injection onshore crude oil extraction in this study. All steam injection is assumed to occur onshore.

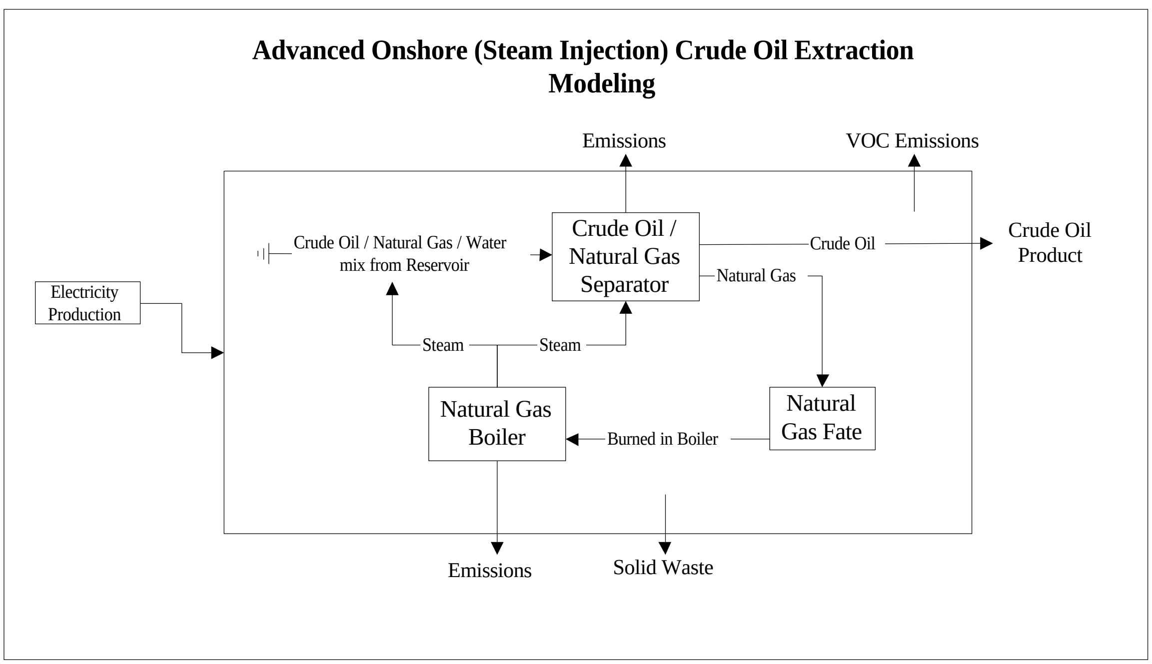

Figure 32: Advanced Onshore (Steam Injection) Crude Oil Extraction

4.2.3.1 Material Use

The raw material inputs required for advanced steam injection onshore crude oil extraction, accounted for in this study, include the crude oil and natural gas in the ground and water used to produce steam. It is assumed that there is no loss of crude oil once it is extracted from the well.

The life cycle environmental flows associated with producing capital equipment and the facilities used to extract crude oil are excluded from this study. However, the energy required for drilling and exploration is included in the study and is assumed to be the same as onshore crude oil production exploration and drilling energy, or 0.75% of the energy in the produced crude oil (Delucchi 1993). This energy is accounted for by increasing the amount of crude oil in the ground needed to produce 1 kg of crude oil. Therefore, advanced steam injection onshore crude oil extraction would require 1.0075 kg of crude oil in the ground to produce 1 kg of crude oil.

The material requirements for both domestic and foreign advanced steam injection onshore crude oil extraction are assumed to be the same.

4.2.3.2 Energy/Equipment Use

Energy used to extract the crude oil is assumed to come from the gross natural gas production of the well and from purchased electricity. Energy requirements for both domestic and foreign advanced steam injection onshore crude oil production are based on a steam injection site located in the lower 48 states producing 4.7 x 10^9 kg/yr (3.45 x 10^7 bbl/yr) of crude oil (DOE 1983) as follows:

Electricity:	11.3 kWh/bbl	(used in pumping)
Natural Gas:	986 MJ/bbl	(used in recovery and steam boiler)

This site is assumed to require the same amount of electricity as the conventional onshore crude oil extraction site modeled in Section 4.2.1. (we assumed that no electricity is used for steam or injecting steam). However, because the amount of oil produced from the steam injection site is less than that of the conventional site, more electricity is required per barrel of oil extracted.

We assumed that all steam is produced by natural gas-fired boilers using associated gas, although several large sites in the United States use purchased natural gas. The estimate of steam use per year is based on the amount of water used by the site (1.06 x 10^{10} L/yr). The energy necessary to convert this water to steam is based on the enthalpy of the steam (2.6 MJ/kg @ approximately 150 psi and 177°C) and a boiler efficiency of 80%. The energy required to run the separators (separating the crude oil, natural gas, and water from each other) is assumed to be included in this estimate.

Electricity is assumed to come from a generic (national average) U.S. grid as previously described in Section 4.2.1.2. See this same section for assumptions concerning foreign electricity production and use in crude oil extraction.

4.2.3.3 Process Emissions

The process emissions from advanced steam injection onshore crude oil extraction include air emissions and solid waste emissions.

No wastewater is assumed to be produced by advanced steam injection onshore crude oil extraction because it is assumed to be reused for steam production. Advanced steam injection onshore extraction is actually a net user of water. Advanced steam injection onshore crude oil extraction is assumed to produce 1 x 10^{-4} kg of waste oil and grease per kg of crude oil produced although no wastewater is produced (DOE 1983).

The emission factor for the production of solid waste is calculated as 0.0098 g of solid waste produced for every kg of crude oil (Tyson et al., 1993).

Air emissions from advanced steam injection onshore crude oil extraction come from the combustion of natural gas in a boiler (see Appendix A) and volatilization (i.e., fugitive) emissions of crude oil. VOC emissions from onshore crude oil extraction (Table 21) are assumed to reflect those from steam injection extraction. The speciation of these emissions are assumed to be the same as in Table 22, as other data are not available. The VOC emissions, and the speciation data, are handled as described in Section 4.2.1.3.

4.2.3.4 Crude Oil and Natural Gas Allocation-Steam Injection Extraction

Advanced onshore crude oil extraction is assumed to burn all of the natural gas produced by the well in order to generate the steam needed for injection. Therefore, no natural gas is produced as a coproduct of advanced steam injection onshore crude oil extraction. Emissions from natural gas boilers and fugitive emissions as well as raw materials, and energy use are allocated completely to crude oil production for advanced steam injection onshore crude oil extraction.

4.2.4 Advanced Onshore Extraction (CO_2 Injection)

Figure 33 shows the system process diagram associated with advanced onshore crude oil extraction through the use of CO_2 injection. It demonstrates the system boundaries and process flows modeled for advanced CO_2 injection onshore crude oil extraction in this study.

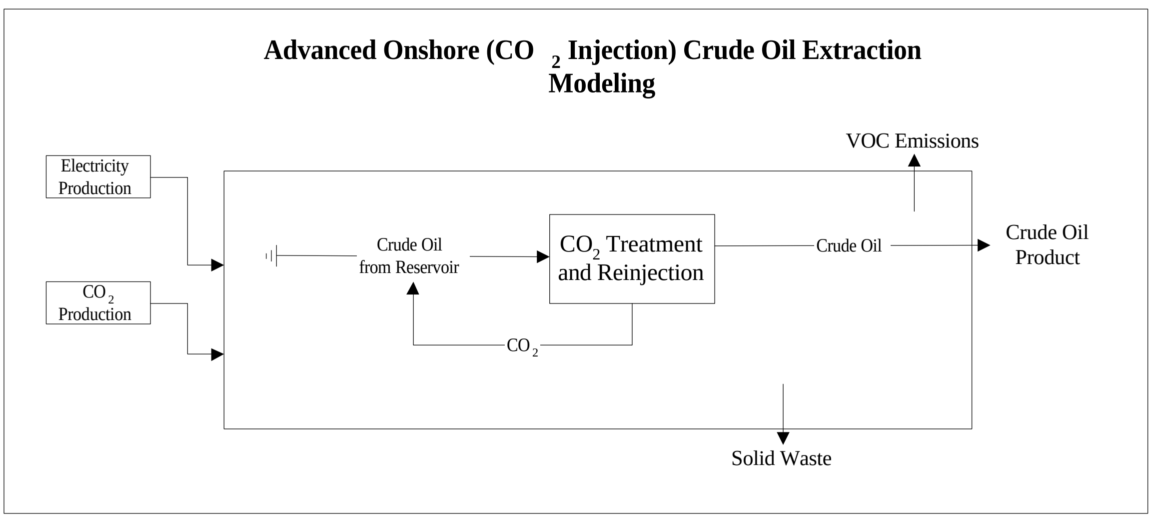

Figure 33: Advanced Onshore (CO_2 Injection) Crude Oil Extraction

4.2.4.1 Material Use

The material inputs required for advanced CO_2 injection onshore crude oil extraction, accounted for in this study, include the crude oil in the ground and the CO_2 required for injection. A CO_2 gas injection well is assumed to require 4.6 kg of CO_2 to be injected for every 1 kg of crude oil produced (15,000 scf of CO_2 per barrel of crude oil) (AOSTRA 1993). Of this CO_2 injected, half is assumed to be produced with the crude oil extracted, which is subsequently removed and reinjected. The remaining 2.3 kg of CO_2 gas (per kg of crude oil extracted) is manufactured and injected[28]. The production of the CO_2 gas is taken from Ecobalance's database DEAM™.

We assumed that there is no loss of crude oil once it is extracted from the well. Only the energy required for drilling and exploration are included in the study; capital equipment and facilities are assumed to be outside the study boundaries as previously discussed. The assumption for energy consumed for onshore crude oil exploration and drilling from section 4.2.1.1, 0.75% of the energy in the produced crude oil, is assumed for CO_2 injection. This energy is accounted for by increasing the amount of crude oil in the ground needed to produce 1 kg of crude oil. Therefore, advanced CO_2 injection onshore crude oil extraction would require 1.0075 kg of crude oil in the ground to produce 1 kg of crude oil. The material requirements for both domestic and foreign advanced CO_2 injection onshore crude oil extraction are assumed to be the same.

4.2.4.2 Energy/Equipment Use

Because we lacked specific energy data describing enhanced/advanced crude oil extraction by CO_2 injection, we assumed that CO_2 injection required the same amount of electricity as the steam injection enhanced/advanced crude oil extraction (section 4.2.3). It is also assumed that this electricity is used to separate, dry, compress, and inject the CO_2 gas.

Electricity:	11.3 kWh/bbl	(Used in pumping)

Electricity for foreign and domestic advanced CO_2 injection processes is assumed to come from a generic (national average) U.S. grid. See section 4.2.1.2 for more information.

4.2.4.3 Process Emissions

The process emissions from advanced CO_2 injection onshore crude oil extraction include air emissions and solid waste emissions.

No wastewater is assumed to be produced by advanced CO_2 injection onshore crude oil extraction. However, advanced CO_2 injection onshore crude oil extraction is assumed to produce oil and grease, estimated to be 1×10^{-4} kg/kg crude oil produced (DOE 1983).

The emission factor for the production of solid waste is calculated as 0.0098 g of solid waste are produced for every kg of crude oil (Tyson et al. 1993).

Air emissions from advanced CO_2 injection onshore crude oil extraction come from volatilization (i.e., fugitive) emissions of crude oil. VOC emissions are assumed to be the same as those from conventional onshore crude oil extraction (Table 21 and Table 22). In 1994 the average productivity of U.S. crude oil production wells was 1,555 kg of crude oil/day per well (11.4 bbl/day per well) (EIA 1995b). Using this number, VOC emission data can be calculated per kg of crude oil produced.

The use of CO_2 injection to enhance the production of crude oil is assumed to result in some sequestration of the injected CO_2. We assumed that half the injected CO_2 is sequestered and, therefore, is accounted for as a negative flow in the life cycle.

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[28] This sequestered CO_2 is accounted for as a negative flow in the model.

4.2.4.4 Crude Oil and Natural Gas Allocations - CO_2 injection

It is assumed that advanced CO_2 injection onshore crude oil extraction does not produce natural gas as a coproduct of crude oil extraction. Fugitive emissions as well as raw materials and energy use are allocated completely to crude oil production for advanced CO_2 injection onshore crude oil extraction.

4.2.5 Crude Oil Extraction Results

A schematic of the system model for both foreign and domestic crude oil production is shown in Figure 34. The corresponding life cycle flows calculated by the TEAM™ model for domestic and foreign oil production and the three modules which feed into oil production are shown in Table 31and Table 32.

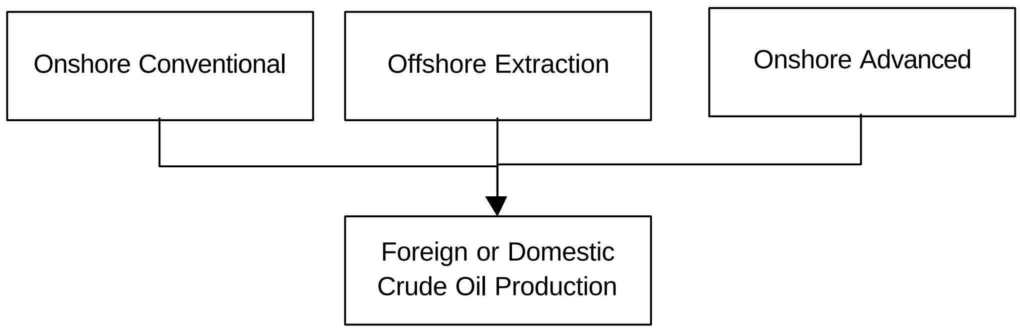

Figure 34: Schematic of Crude Oil Production System Modeled in TEAM™

Table 31: LCI Results for Domestic Crude Oil Extraction (for 1 kg of crude oil)

	Units	Domestic Crude Oil Production	Onshore Conventional Extraction	Conventional Offshore Extraction	Onshore Advanced Extraction
Raw Materials					
Coal (in ground)	kg	0.01306	0.00968	0.00000	0.00338
Oil (in ground)	kg	1.02145	0.69551	0.21500	0.11094
Natural Gas (in ground)	kg	0.06525	0.00436	0.00307	0.05782
Uranium (U, ore)	kg	0.00000	0.00000	0.00000	0.00000
Phosphate Rock (in ground)	kg	0.00000	0.00000	0.00000	0.00000
Potash (K_2O, in ground)	kg	0.00000	0.00000	0.00000	0.00000
Perlite (SiO_2, ore)	kg	0.00000	0.00000	0.00000	0.00000
Limestone ($CaCO_3$, in ground)	kg	0.00249	0.00184	0.00000	0.00065
Sodium Chloride (NaCl)	kg	0.00000	0.00000	0.00000	0.00000
Water Used (total)	liter	0.22170	0.00030	0.00000	0.22140
Air Emissions					
Carbon Dioxide (CO_2, fossil)	g	46.63270	38.93490	8.98844	-1.29060
Carbon Dioxide (CO_2, biomass)	g	0.00000	0.00000	0.00000	0.00000
Methane (CH_4)	g	0.49569	0.20565	0.01859	0.27145
Nitrous Oxide (N_2O)	g	0.04432	0.00056	0.00022	0.04354
Carbon Monoxide (CO)	g	0.06668	0.02833	0.00883	0.02953
Hydrocarbons (except methane)	g	0.14941	0.11073	0.01510	0.02357
Hydrocarbons (unspecified)	g	0.00107	0.00079	0.00000	0.00028
Benzene	g	0.00023	0.00017	0.00003	0.00004
Formaldehyde	g	0.00303	0.00000	0.00303	0.00000
Particulates (PM10)	g	0.00212	0.00003	0.00017	0.00192
Particulates (unspecified)	g	0.18387	0.13616	0.00000	0.04771
Sulfur Oxides (SO_x as SO_2)	g	1.40728	0.26233	0.00093	1.14402
Nitrogen Oxides (NO_x as NO_2)	g	0.26273	0.09849	0.00977	0.15447
Hydrogen Chloride (HCl)	g	0.00705	0.00522	0.00000	0.00183
Hydrogen Fluoride (HF)	g	0.00088	0.00065	0.00000	0.00023
Ammonia (NH_3)	g	0.00000	0.00000	0.00000	0.00000
Agrochemicals (unspecified)	g	0.00000	0.00000	0.00000	0.00000
BOD5 (Biochemical Oxygen Demand)	g	0.00017	0.00013	0.00000	0.00004
COD (Chemical Oxygen Demand)	g	0.00143	0.00106	0.00000	0.00037
Metals (unspecified)	g	0.01953	0.00348	0.01605	0.00000
Ammonia (NH_4+ NH_3 as N)	g	0.00004	0.00003	0.00000	0.00001
Nitrates (NO_3-)	g	0.00001	0.00001	0.00000	0.00000
Solid Waste (hazardous)	kg	0.00000	0.00000	0.00000	0.00000
Solid Waste (non-hazardous)	kg	0.00479	0.00355	0.00000	0.00124
Total Primary Energy	MJ	47.04950	30.00660	9.17476	7.86822
Fossil Energy	MJ	47.02950	29.99170	9.17476	7.86304
Fuel Energy	MJ	2.96633	0.65396	0.66676	1.64561

Table 32: LCI Results for Foreign Crude Oil Extraction (for 1 kg of crude oil)

	Units	Foreign Crude Oil Production (Total)	Onshore Conventional	Conventional Offshore Extraction	Onshore Advanced
Raw Materials					
Coal (in ground)	kg	0.01156	0.01064	0.00000	0.00092
Oil (in ground)	kg	1.02140	0.77614	0.21500	0.03026
Natural Gas (in ground)	kg	0.03444	0.01358	0.00509	0.01577
Uranium (U, ore)	kg	0.00000	0.00000	0.00000	0.00000
Phosphate Rock (in ground)	kg	0.00000	0.00000	0.00000	0.00000
Potash (K_2O, in ground)	kg	0.00000	0.00000	0.00000	0.00000
Perlite (SiO_2, ore)	kg	0.00000	0.00000	0.00000	0.00000
Limestone ($CaCO_3$, in ground)	kg	0.00220	0.00203	0.00000	0.00018
Sodium Chloride (NaCl, in ground or in sea)	kg	0.00000	0.00000	0.00000	0.00000
Water Used (total)	liter	0.06071	0.00033	0.00000	0.06038
Air Emissions					
Carbon Dioxide (CO_2, fossil)	g	79.18740	66.31410	13.22530	-0.35198
Carbon Dioxide (CO_2, biomass)	g	0.00000	0.00000	0.00000	0.00000
Methane (CH_4)	g	1.03591	0.45854	0.50334	0.07403
Nitrous Oxide (N_2O)	g	0.01272	0.00061	0.00023	0.01187
Carbon Monoxide (CO)	g	0.12269	0.09475	0.01989	0.00805
Hydrocarbons (except methane)	g	0.17158	0.14559	0.01956	0.00643
Hydrocarbons (unspecified)	g	0.00094	0.00087	0.00000	0.00008
Benzene	g	0.00022	0.00018	0.00003	0.00001
Formaldehyde	g	0.00311	0.00000	0.00311	0.00000
Particulates (PM10)	g	0.00073	0.00003	0.00018	0.00052
Particulates (unspecified)	g	0.16270	0.14969	0.00000	0.01301
Sulfur Oxides (SO_x as SO_2)	g	0.92057	0.56113	0.04743	0.31201
Nitrogen Oxides (NO_x as NO_2)	g	0.17394	0.11982	0.01199	0.04213
Hydrogen Chloride (HCl)	g	0.00624	0.00574	0.00000	0.00050
Hydrogen Fluoride (HF)	g	0.00078	0.00072	0.00000	0.00006
Ammonia (NH3)	g	0.00000	0.00000	0.00000	0.00000
Agrochemicals (unspecified)	g	0.00000	0.00000	0.00000	0.00000
BOD5 (Biochemical Oxygen Demand)	g	0.00015	0.00014	0.00000	0.00001
COD (Chemical Oxygen Demand)	g	0.00126	0.00116	0.00000	0.00010
Metals (unspecified)	g	0.02029	0.00382	0.01646	0.00000
Ammonia (NH_4 +, NH_3, as N)	g	0.00004	0.00003	0.00000	0.00000
Nitrates (NO_3-)	g	0.00001	0.00001	0.00000	0.00000
Solid Waste (hazardous)	kg	0.00000	0.00000	0.00000	0.00000
Solid Waste (nonhazardous)	kg	0.00424	0.00390	0.00000	0.00034
Total Primary Energy	MJ	44.81250	33.47480	9.19190	2.14588
Fossil Energy	MJ	44.79480	33.45850	9.19190	2.14446
Fuel Energy per kg of Crude Oil	MJ	42.54	-	-	-

4.3 Crude Oil Transport to Refinery

The United States is divided into PADDs to ensure that each region or PADD is supplied with enough petroleum for strategic defense reasons. The transportation distances used in this report are regionalized by these PADDs. However, no specific ton-mile information is available for crude oil transportation per PADD. Therefore, certain assumptions have to be made regarding crude oil transportation as described in the following sections:

- ***Section 4.3.1:*** This section describes how the modes of transportation are regionalized per PADD.
- ***Section 4.3.2:*** This section explains how transportation distances for each PADD are based on U.S. average distances.
- ***Section 4.3.3:*** This section explains the various transportation models used to represent the modes of transportation.
- ***Section 4.3.4:*** This section describes how the pumping and fugitive emissions of transportation are taken into account.
- ***Section 4.3.5:*** This section provides the LCI results for transporting 1 bbl of crude oil.

4.3.1 Transportation Regionalization

The amount of foreign and domestic crude oil transported into each PADD is estimated from refinery receipts of crude oil which is known for each PADD.[29] Table 33 and Table 34 describe refinery receipt of crude oil for 11 methods of transport and two sources, foreign and domestic.

Table 33: Refinery Receipts of Crude Oil by Source and by PADD (1993)

Source	Petroleum Administration for Defense District					
	I	**II**	**III**	**IV**	**V**	**Total U.S.**
Total:	(%)	(%)	(%)	(%)	(%)	(%)
Domestic	2.68	56.03	39.37	81.33	90.12	50.41
Foreign	97.32	43.97	60.63	18.67	9.88	49.59
Total	100	100	100	100	100	100

Pipeline transportation for Canadian and other foreign sources are estimated separately. This is done to account for the fact that foreign oil, other than Canadian, must travel via tanker to the United States before it enters a domestic pipeline[30].

[29] Source: EIA Petroleum Supply Annual 1993, Vol. 1. 1993 data were used because that was the latest year for which information used to calculate transportation distances could be found.

[30] Note: Transportation of crude oil within foreign countries is limited to pipelines. This seems to be a fair estimate considering the small amount of crude oil shipped by alternate methods in the United States. 15% of all foreign oil (excluding Canada) will travel in a foreign pipeline before being shipped to the United States (DeLucchi, 1993).

Table 34: Refinery Receipts of Crude Oil by Method of Transportation and by PADD (1993)

Method	Petroleum Administration for Defense District					
	I	**II**	**III**	**IV**	**V**	**Total U.S.**
Pipeline:	(%)	(%)	(%)	(%)	(%)	(%)
Domestic	13.3	96.9	84.4	86.8	38.6	71.9
Foreign	0.17	51.8	22.9	0	0	23.2
Canadian	4.59	48.2	0.31	99.8	18.1	12.5
Tanker:						
Domestic	1.73	0	0.78	0	59.5	20.2
Foreign	90.7	0	75.7	0	70.5	62.4
Barge:						
Domestic	10.7	0.19	11.8	0	0.67	4.57
Foreign	4.57	0	1.12	0	11.4	1.92
Tank Cars:						
Domestic	41.2	0	0.08	0.65	0.21	0.34
Foreign	0	0	0	0.19	0	0
Trucks:						
Domestic	33.1	2.93	2.99	13.1	0.98	2.98
Foreign	0	0	0	0	0	0
Total:						
Domestic	100	100	100	100	100	100
Foreign	100	100	100	100	100	100

4.3.2 Transportation Distances

Crude oil transportation distances are based on national average distances according to the amount of crude transported by each mode. The data and assumptions are described below.

Crude oil transported via domestic tankers and domestic barges was based on data provided by the Army Corp of Engineer's Report *Waterborne Commerce of the United States, Calendar Year 1993, Part 5 - National Summaries.* The Army report lists tons and ton-miles of crude oil transported by tanker and barge on all U.S. waterways. The data listed are not just for refinery receipts, but include all transport (including any transport to storage facilities). Average miles are calculated by dividing total ton-miles traveled by total tons transported. This is done separately for both tanker and barge.

Crude oil transported through domestic pipelines are characterized by the Association of Oil Pipelines, using data from Annual Report (Form 6) of oil pipeline companies to the Federal Energy Regulatory Commission (EIA Petroleum Supply Annual 1993, vol. 1). The Association of Oil Pipelines provides estimates of total ton-miles of crude oil carried in domestic pipelines. Petroleum Supply Annual Table 46 provides estimates of refinery receipts of barrels of crude oil by PADD, by method, and source of transportation. The data in Table 46 are converted to tons.[31] Average miles are calculated by dividing total ton-miles of crude oil, carried in domestic pipelines, by the tons of crude oil received at refineries via pipeline.

Crude oil transported by domestic rail is characterized by the Association of Oil Pipelines, using data from *Carload Way Bill Statistics*, Report TD-1 (U.S. Department of Transportation); the *Federal Railroad Administration Annual*; and the *Freight Commodity Statistics*, Association of American Railroads Annual as reported by the EIA (Petroleum Supply Annual, 1993, vol. 1). The Association of Oil Pipelines provides estimates of total ton-miles of crude oil carried by rail in the United States. Petroleum Supply Annual Table 46 provides estimated refinery receipts of barrels of crude oil by PADD, by method, and by source of transportation. Table 46 gives crude oil receipts in barrels, which are converted to tons. Average miles are calculated by dividing total ton-miles of crude oil, carried by rail, by tons of crude oil received at refineries via railroad tank cars.

Crude oil transported by domestic trucking firms is also provided by the Association of Oil Pipelines, using data from *Financial and Operating Statistics* American Trucking Association, Inc. as reported by the EIA (Petroleum Supply Annual, 1993, Vol. 1). The Association of Oil Pipelines provides estimated total ton-miles of crude oil transported by motor carriers in the United States. Petroleum Supply Annual Table 46 provides estimates of refinery receipts of barrels of crude oil by PADD, by method, and by source of transportation. Table 46 gives crude oil receipts in barrels, which are converted to tons. Average miles are calculated by dividing total ton-miles of crude oil, transported by motor carriers, by tons of crude oil received at refineries via truck.

The estimated average miles per ton that were calculated for domestic pipelines were used for characterizing crude oil transported via foreign pipeline from the field to the coast and for moving crude oil within Canadian pipelines to the United States.

Information describing crude oil transported via foreign tankers was taken from a previous study by Delucchi (1993) and DOE (EIA, Petroleum Supply Annual, 1994, vol. 1). The DOE report provided estimates of imported crude oil by country for each PADD in barrels. PADD I crude oil is assumed to all arrive at New York. PADD II and III oil is assumed to arrive at Houston. (PADD II oil arrives at Houston and then is transported by pipeline, barge, etc. to its final destination). PADD V oil is assumed to arrive at Los Angeles. PADD IV receives no foreign oil except from Canada.

The nautical miles between ports of origin and U.S. ports (New York, Houston, and Los Angeles) are given in Delucchi's study, based on information from the Defense Mapping Agency[32]. From this information a weighted average is calculated for each PADD, by multiplying barrels imported from each country by the distance from that country to the specified U.S. port of entry. These results, in barrel-miles for each PADD, are added together and then divided by the total number of barrels imported to get an average distance traveled by the foreign tankers (in miles). Average mileage values for all modes of transportation are then converted into kilometers.

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[31] Conversion of crude oil from barrels to tons is done using the conversion factor of 6.62 bbl equals one ton (EIA, 1994).

[32] Defense Mapping Agency, Hydrographic/Topographic Center, Distance Between Ports, Fifth edition, Publication 151, Washington, DC (1995).

4.3.3 Transportation Models

Ecobalance maintains a database of transportation methods and environmental impacts associated with those methods. This database, DEAM™ is used to account for the environmental impacts of transporting crude oil from extraction sites to refinery locations.

Transporting crude via pipelines consumes electricity drawn from the U.S. average power mix. In this study 0.0184 kWh electricity per ton-mile was assumed[33]. Rail and truck transportation was estimated assuming that #2 diesel fuel was used. Ocean tankers and barges were assumed to use #6 fuel oil.

To make the diesel fuel consumed in the rail and truck sector consistent with the results of this analysis (which estimates #2 diesel life cycle impacts), the DEAM™ model was run in a reiterating mode. The model was run the first time with values for production of #2 diesel fuel based on Ecobalance's database. Those results were then used to replace the original factors in DEAM™, then the model was run a second time with the new values to obtain the final result. Empty backhauls were taken into account for truck transportation.

Figure 35 demonstrates graphically how crude oil transportation is regionalized in this study. Example percentages for mode of transport are given for PADD II to clarify how the information is used.

4.3.4 Energy and Fugitive Emissions from Storage and Handling

In addition to the energy requirements and subsequent emissions from the actual modes of transportation (e.g., truck diesel use and emissions, pipeline electricity requirements, and emissions from electricity production), energy and emissions are also created during the loading and unloading of the crude oil.

The loading and unloading of crude oil is assumed to require electricity for pumping. The amount of electricity used is based on the electricity required for pipeline transport. Pipelines are assumed to require 5.8×10^{-5} MJ of electricity per 1 kg transported 1 km. For loading and unloading, we assumed that the distance fuel would be pumped is 50 meters and that the energy required for pumping is linear with distance pumped. Therefore, 2.9×10^{-6} MJ of electricity are required for loading and unloading 1 kg of fuel. Life cycle flows for electricity used in this stage are based on a generic (national average) U.S. grid.

The emissions associated with loading and unloading trucks and rail cars were based on the following formula (US EPA AP-42):

$$L_L = 12.46\frac{SPM}{T}(1-\frac{eff}{100})$$

Equation 1: Estimating Emissions from Loading and Unloading Trucks and Rail Cars

Where:

L_L = loading loss in pounds per 1000 gallons
S = saturation factor
P = true vapor pressure of fuel transported (psia)
M = molecular weight of fuel vapors (lb/lb-mole)
T = temperature of the fuel ($^oR(^oF + 460)$)
eff = overall reduction efficiency (%)

[33] Banks, W. F., Energy Consumption in the Pipeline Industry, SAN-1171-1/3, Systems, Science, and Software, La Jolla, CA, for the U.S. Department of Energy, December (1977).

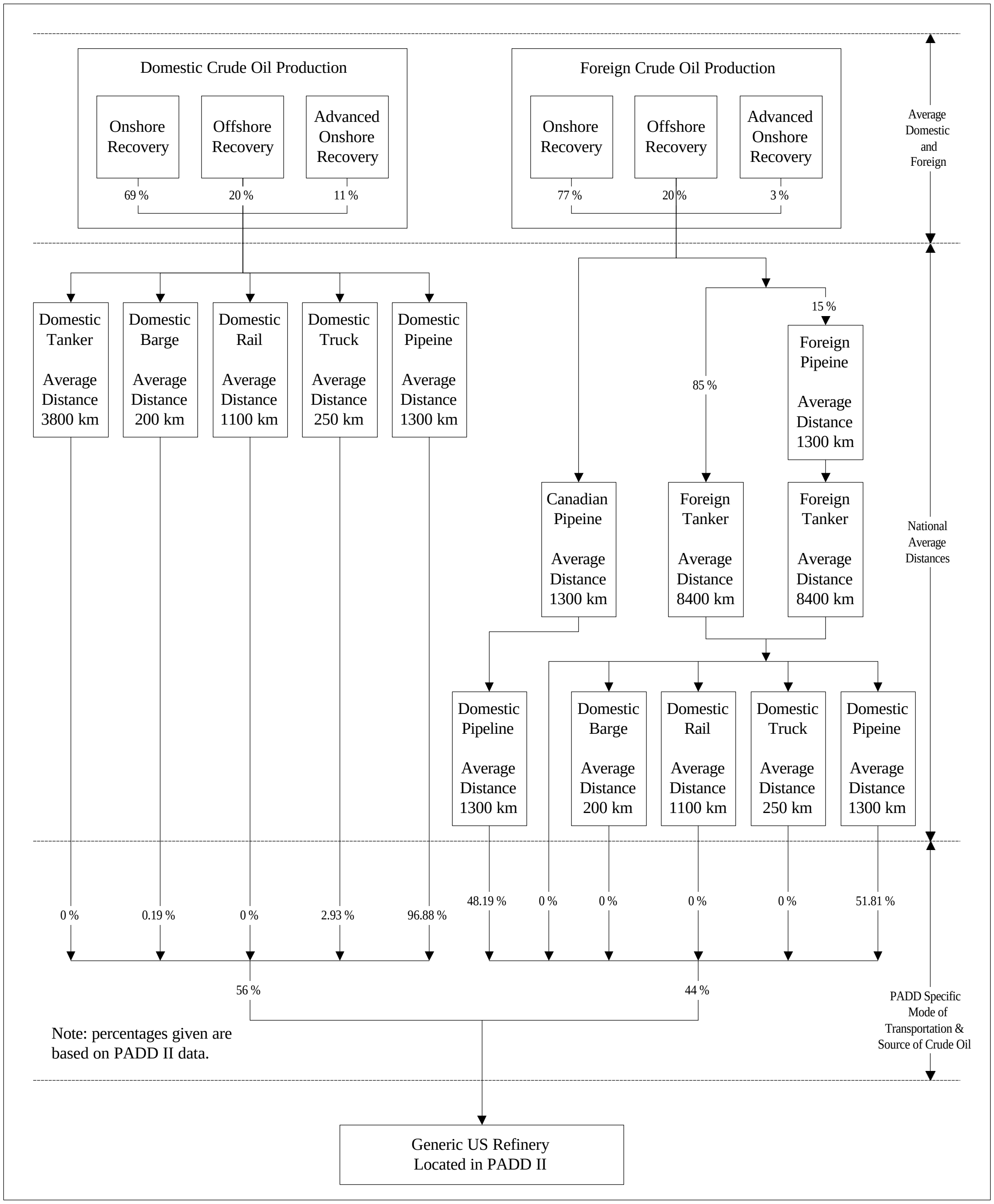

Figure 35: Modes of Transport and Distances for Crude Oil

The saturation factor is based on the type of carrier and the mode of operation[34]. For this project an average S value is used that is the straight average of all possible operation modes.

The vapor pressure of the fuel (in this case, crude oil) is estimated at 160^{o}F based on information in AP-42. The M (or molecular weight of the crude oil vapors) is also taken from information in AP-42. The temperature is assumed to be 160^{o}F to match the vapor pressure and molecular weight data.

The reduction efficiency is a measure of how much of the vapors are collected, then subsequently controlled. In this case it is assumed that 70% of the vapors were collected and then 90% of those collected vapors were controlled to yield and overall efficiency of 63%[35].

The emissions associated with loading and unloading tankers and barges were based on the following formula (US EPA AP-42):

$$C_L = (C_A + 1.84(0.44P - 0.42)\frac{MG}{T})$$

Equation 2: Estimating Emissions from Loading and Unloading Tankers and Barges

Where:

C_L = total loading loss in pounds per 1000 gallons
C_A = arrival emission factor (lb/1000 gal.)
P = true vapor pressure of fuel transported (psia)
M = molecular weight of fuel vapors (lb/lb-mole)
G = vapor growth factor = 1.02 (dimensionless)
T = temperature of the vapors (^{o}R (^{o}F + 460))
eff = overall reduction efficiency (%)

The arrival emission factor is based on information in AP-42 and is determined by the condition of the transportation vessel upon arrival. In this project it is assumed to be an uncleaned vessel[36].

The vapor pressure of the fuel (in this case, crude oil) is estimated at 160^{o}F based on information in AP-42. The M (or molecular weight of the crude oil vapors) is also taken from information in AP-42. The temperature is assumed to be 160^{o}F to match the vapor pressure and molecular weight data.

In addition to loading and unloading fugitive emissions there are also fugitive emissions associated with transit of the fuel. The emissions associated with truck, train, tanker, and barge transit were based on the following formula (US EPA AP-42):

$$L_T = 0.1PW$$

Equation 3: Estimating Fuel Transit Emissions

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[34] The different types of carriers include normal service and vapor balance service in which the cargo truck retrieves the vapors displaced during product unloading and transports them back to the loading terminal. Modes of operation include submerged and splash loading.

[35] Both the 70% collection efficiency and 90% control efficiency are the low range of values reported in AP-42.

[36] Therefore, no ballast emissions are accounted for.

Where:

L_T = transit losses in pounds per 1000 gal/wk
P = true vapor pressure of fuel transported (psia)
W = density of the condensed vapors (lb/gal)

The vapor pressure of the fuel (in this case, crude oil) is estimated at 160^{o}C based on information in AP-42. The W (or density of the condensed crude oil vapors) is also taken from information in AP-42.

The value obtained for L_T can be converted to pounds per 1000 gal/km based on the speed of the modes of transportation used. The following conversion factors are computed from average speeds for the modes of transport:

Tanker - 1 week = 4,317.6 km

Barge - 1 week = 2,167.2 km

Rail - 1 week = 10,752 km

Truck[37] - 1 week = 5,792 km

Figure 36 shows how crude oil transportation was modeled in this project. Note that fugitive tank emissions from the storage of crude oil at the oil field are accounted for in crude oil extraction modeling. Also, fugitive tank emissions from the storage of crude oil at the refinery are accounted for in the crude oil refining model.

[37] Assuming the truck is running at 60 mph for 10 hours a day and 6 days a week.

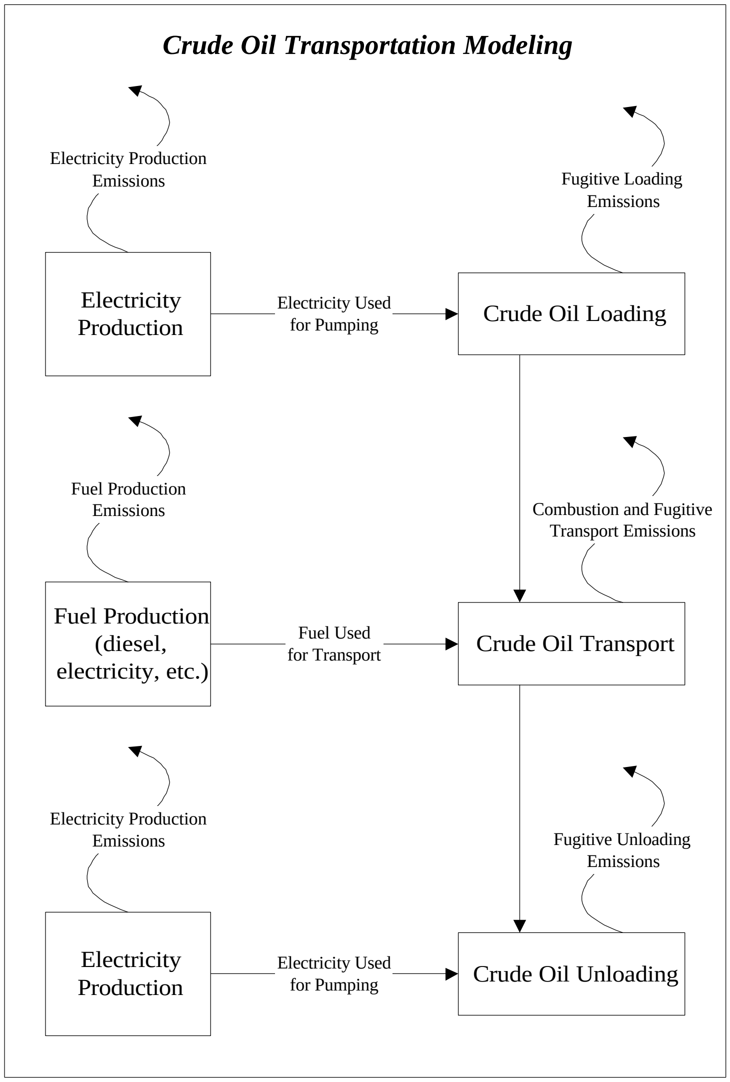

Figure 36: Contributions to Life Cycle Flows for Transport and Handling of Crude Oil

4.3.5 Crude Oil Transportation Results

Figure 37 and Figure 38 present schematics of the system modeled in the TEAM™ software for domestic and foreign crude oil transport, respectively. Table 35 and Table 36 show the corresponding LCI results for domestic and foreign crude oil, respectively, for the transport of 1 kg of crude oil to a generic U.S. refinery location.

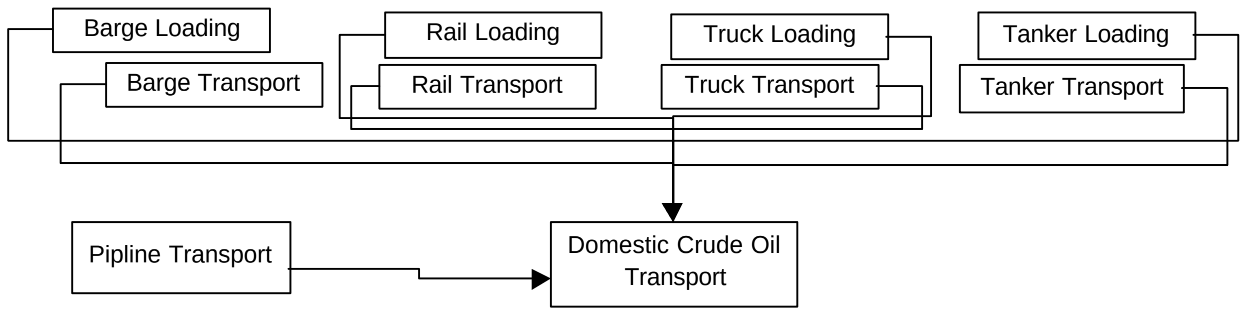

Figure 37: Schematic of TEAM™ Model Inputs to Domestic Oil Transport

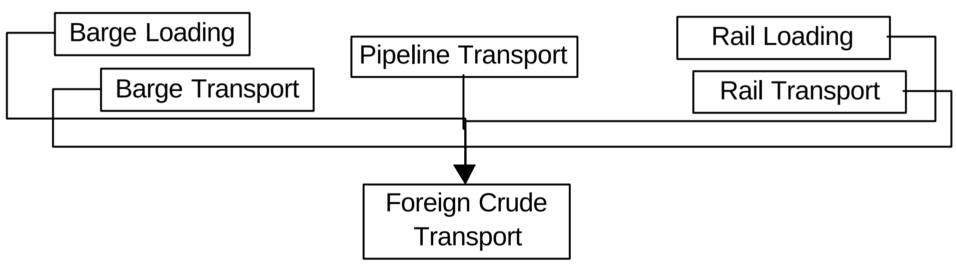

Figure 38: Schematic of TEAM Model Inputs to Foreign Oil Transport

Table 35: LCI Results for Domestic Crude Oil Transportation (for 1 kg of crude oil)

	Units	Domestic Crude Oil Transport (Total)	Tanker Loading	Tanker Transport	Barge Loading	Barge Transport	Railcar Loading	Rail Transport	Truck Loading	Truck Transport	Pipeline Transport
Raw Materials											
Coal (in ground)	kg	0.003654	4.89E-08	4.03E-05	2.75E-08	3.18E-06	1.74E-08	1.00E-05	2.44E-08	9.63E-06	0.003591
Oil (in ground)	kg	0.002149	1.68E-09	0.001292	9.48E-10	0.000102	5.99E-10	0.000322	8.40E-10	0.000309	0.000124
Natural Gas (in ground)	kg	0.000568	5.37E-09	0.000111	3.02E-09	8.76E-06	1.91E-09	2.77E-05	2.68E-09	2.65E-05	0.000394
Uranium (U, ore)	kg	8.76E-08	1.17E-12	9.61E-10	6.60E-13	7.59E-11	4.17E-13	2.39E-10	5.85E-13	2.30E-10	8.61E-08
Phosphate Rock (in ground)	kg	0	0	0	0	0	0	0	0	0	0
Potash (K_2O, in ground)	kg	0	0	0	0	0	0	0	0	0	0
Perlite (SiO_2, ore)	kg	4.60E-07	0	2.94E-07	0	2.32E-08	0	7.32E-08	0	7.02E-08	0
Limestone ($CaCO_3$, in ground)	kg	0.000697	9.33E-09	7.65E-06	5.25E-09	6.04E-07	3.32E-09	1.91E-06	4.66E-09	1.83E-06	0.000685
Sodium Chloride (NaCl)	kg	0	0	0	0	0	0	0	0	0	0
Water Used (total)	liter	0.000392	1.50E-09	0.000180	8.46E-10	1.42E-05	5.34E-10	4.48E-05	7.50E-10	4.30E-05	0.000110
Air Emissions											
Carbon Dioxide (CO_2, fossil)	g	17.8928	0.000152	4.31102	8.53E-05	0.343858	5.39E-05	1.08413	7.56E-05	1.02877	11.1247
Carbon Dioxide (CO_2, biomass)	g	0	0	0	0	0	0	0	0	0	0
Methane (CH_4)	g	0.029077	3.65E-07	0.001388	2.06E-07	0.000110	1.30E-07	0.000390	1.82E-07	0.000369	0.026820
Nitrous Oxide (N_2O)	g	0.000369	2.80E-09	4.64E-05	1.58E-09	3.66E-06	9.95E-10	1.16E-05	1.40E-09	0.000102	0.000205
Carbon Monoxide (CO)	g	0.011651	3.36E-08	0.000930	1.89E-08	0.001148	1.19E-08	0.003618	1.68E-08	0.003490	0.002465
Hydrocarbons (except	g	0.001129	1.23E-09	0.000216	6.92E-10	1.71E-05	4.37E-10	5.40E-05	6.13E-10	0.000751	0.000090
Hydrocarbons (unspecified)	g	0.111550	0.033145	0.020609	0.018665	0.001493	0.014540	0.001995	0.020402	0.000407	0.000293
Benzene	g	4.54E-07	0	2.90E-07	0	2.29E-08	0	7.22E-08	0	6.93E-08	0
Formaldehyde	g	6.08E-06	7.89E-18	3.88E-06	4.44E-18	3.06E-07	2.81E-18	9.67E-07	3.94E-18	9.28E-07	5.79E-13
Particulates (PM10)	g	0.001744	0	0	0	0.000139	0	0.000438	0	0.001167	0
Particulates (unspecified)	g	0.054249	6.88E-07	0.003192	3.88E-07	7.25E-05	2.45E-07	0.000229	3.44E-07	0.000220	0.050534
Sulfur Oxides (SO_x as SO_2)	g	0.121741	8.64E-07	0.054722	4.87E-07	0.000500	3.07E-07	0.001578	4.31E-07	0.001515	0.063424
Nitrogen Oxides (NO_x)	g	0.072804	4.70E-07	0.005058	2.65E-07	0.005673	1.67E-07	0.017883	2.35E-07	0.009680	0.034510
Hydrogen Chloride (HCl)	g	0.001972	2.64E-08	2.16E-05	1.49E-08	1.71E-06	9.39E-09	5.39E-06	1.32E-08	5.17E-06	0.001938
Hydrogen Fluoride (HF)	g	0.000246	3.30E-09	2.71E-06	1.86E-09	2.14E-07	1.17E-09	6.74E-07	1.65E-09	6.46E-07	0.000242
Ammonia (NH_3)	g	2.02E-08	1.80E-13	4.01E-09	1.01E-13	3.17E-10	6.40E-14	1.37E-09	8.98E-14	1.32E-09	1.32E-08
Water Emissions											
Agrochemicals (unspecified)	g	0	0	0	0	0	0	0	0	0	0
BOD5 (Biochemical Oxygen Demand)	g	0.001405	6.32E-10	0.000867	3.56E-10	6.84E-05	2.25E-10	0.000216	3.15E-10	0.000207	4.64E-05
COD (Chemical Oxygen Demand)	g	0.011886	5.35E-09	0.007335	3.01E-09	0.000579	1.90E-09	0.001828	2.67E-09	0.001753	0.000393
Metals (unspecified)	g	5.91E-05	3.99E-11	3.58E-05	2.25E-11	2.83E-06	1.42E-11	8.93E-06	1.99E-11	8.57E-06	2.93E-06
Ammonia (NH_4+, NH_3, as N)	g	0.000210	1.56E-10	0.000127	8.80E-11	1.00E-05	5.56E-11	3.16E-05	7.80E-11	3.03E-05	1.15E-05
Nitrates (NO_3-)	g	3.12E-06	4.18E-11	3.43E-08	2.35E-11	2.71E-09	1.49E-11	8.54E-09	2.09E-11	8.19E-09	3.07E-06
Solid Waste (hazardous)	kg	4.57E-06	2.06E-12	2.82E-06	1.16E-12	2.23E-07	7.32E-13	7.03E-07	1.03E-12	6.74E-07	1.51E-07
Solid Waste (non-hazardous)	kg	0.001345	1.79E-08	1.93E-05	1.01E-08	1.52E-06	6.37E-09	4.81E-06	8.94E-09	4.62E-06	0.001314
Total Primary Energy	MJ	0.271239	2.40E-06	0.059959	1.35E-06	0.004732	8.55E-07	0.015362	1.20E-06	0.014732	0.176448
Fossil Energy	MJ	0.265639	2.33E-06	0.059897	1.31E-06	0.004727	8.28E-07	0.015347	1.16E-06	0.014718	0.170944
Fuel Energy per kg of Crude Oil	MJ	42.54	-	-	-	-	-	-	-	-	-

Table 36: LCI Results for Foreign Crude Oil Transportation (for 1 kg of crude oil)

	Units	Foreign Crude Oil Transport (Total)	Tanker Loading	Tanker Transport	Barge Loading	Barge Transport	Railcar Loading	Rail Transport	Pipeline Transport
Raw Materials									
Coal (in ground)	kg	0.0041165	3.40E-07	0.0006134	1.30E-08	1.50E-06	2.35E-11	1.36E-08	0.0035012
Oil (in ground)	kg	0.0198367	1.17E-08	0.0196678	4.46E-10	4.80E-05	8.10E-13	4.36E-07	0.0001205
Natural Gas (in ground)	kg	0.0020772	3.73E-08	0.0016889	1.42E-09	4.12E-06	2.58E-12	3.74E-08	0.000384
Uranium (U, ore)	kg	9.86E-08	8.15E-12	1.46E-08	3.11E-13	3.57E-11	5.64E-16	3.24E-13	8.39E-08
Phosphate Rock (in ground)	kg	0	0	0	0	0	0	0	0
Potash (K_2O, in ground)	kg	0	0	0	0	0	0	0	0
Perlite (SiO_2, ore)	kg	4.48E-06	0	4.47E-06	0	1.09E-08	0	9.91E-11	0
Limestone ($CaCO_3$, in ground)	kg	0.0007844	6.49E-08	0.0001164	2.47E-09	2.84E-07	4.49E-12	2.58E-09	0.0006676
Sodium Chloride (NaCl)	kg	0	0	0	0	0	0	0	0
Water Used (total)	liter	0.0028514	1.04E-08	0.0027371	3.98E-10	6.68E-06	7.23E-13	6.06E-08	0.0001075
Air Emissions									
Carbon Dioxide (CO_2, fossil)	g	76.6231	0.0010541	65.6117	4.02E-05	0.161937	7.30E-08	0.0014671	10.8469
Carbon Dioxide (CO_2, biomass)	g	0	0	0	0	0	0	0	0
Methane (CH4)	g	0.0473333	2.54E-06	0.0211286	9.69E-08	5.16E-05	1.76E-10	5.27E-07	0.02615
Nitrous Oxide (N_2O)	g	0.0009081	1.95E-08	0.000706	7.42E-10	1.72E-06	1.35E-12	1.56E-08	0.0002003
Carbon Monoxide (CO)	g	0.0171105	2.34E-07	0.0141615	8.90E-09	0.0005406	1.62E-11	4.90E-06	0.0024033
Hydrocarbons (except methane)	g	0.0033896	8.55E-09	0.0032936	3.26E-10	8.04E-06	5.92E-13	7.31E-08	8.80E-05
Hydrocarbons (unspecified)	g	0.61238	0.230553	0.371922	0.0087901	0.000806	1.97E-05	2.93E-06	0.0002861
Benzene	g	4.42E-06	0	4.41E-06	0	1.08E-08	0	9.77E-11	0
Formaldehyde	g	5.92E-05	5.49E-17	5.91E-05	2.09E-18	1.44E-07	3.80E-21	1.31E-09	5.65E-13
Particulates (PM10)	g	6.61E-05	0	0	0	6.55E-05	0	5.93E-07	0
Particulates (unspecified)	g	0.0978977	4.79E-06	0.0485863	1.83E-07	3.42E-05	3.31E-10	3.10E-07	0.0492719
Sulfur Oxides (SO_x as SO_2)	g	0.894921	6.01E-06	0.832837	2.29E-07	0.0002354	4.16E-10	2.14E-06	0.06184
Nitrogen Oxides (NO_x as NO_2)	g	0.113323	3.27E-06	0.0769758	1.25E-07	0.0026716	2.26E-10	2.42E-05	0.0336481
Hydrogen Chloride (HCl)	g	0.0022197	1.84E-07	0.0003294	7.00E-09	8.04E-07	1.27E-11	7.30E-09	0.0018893
Hydrogen Fluoride (HF)	g	0.0002775	2.30E-08	4.12E-05	8.75E-10	1.01E-07	1.59E-12	9.12E-10	0.0002362
Ammonia (NH_3)	g	7.41E-08	1.25E-12	6.10E-08	4.77E-14	1.49E-10	8.66E-17	1.86E-12	1.29E-08
Water Emissions									
Agrochemicals (unspecified)	g	0	0	0	0	0	0	0	0
BOD5 (Biochemical Oxygen Demand)	g	0.0132701	4.40E-09	0.0131924	1.68E-10	3.22E-05	3.04E-13	2.92E-07	4.52E-05
COD (Chemical Oxygen Demand)	g	0.112286	3.72E-08	0.111628	1.42E-09	0.0002726	2.57E-12	2.47E-06	0.0003828
Metals (unspecified)	g	0.0005498	2.78E-10	0.0005456	1.06E-11	1.33E-06	1.92E-14	1.21E-08	2.86E-06
Ammonia (NH_4+, NH_3, as N)	g	0.0019448	1.09E-09	0.0019289	4.14E-11	4.71E-06	7.52E-14	4.27E-08	1.12E-05
Nitrates (NO_3-)	g	3.52E-06	2.91E-10	5.22E-07	1.11E-11	1.27E-09	2.01E-14	1.16E-11	2.99E-06
Solid Waste (hazardous)	kg	4.32E-05	1.43E-11	4.29E-05	5.45E-13	1.05E-07	9.90E-16	9.51E-10	1.47E-07
Solid Waste (non-hazardous)	kg	0.0015762	1.25E-07	0.000294	4.75E-09	7.18E-07	8.62E-12	6.51E-09	0.0012814
Total Primary Energy	MJ	1.08685	1.67E-05	0.912542	6.37E-07	0.0022286	1.16E-09	2.08E-05	0.172042
Fossil Energy	MJ	1.08055	1.62E-05	0.911607	6.18E-07	0.0022263	1.12E-09	2.08E-05	0.166676
Fuel Energy per kg of Crude Oil	MJ	42.54	-	-	-	-	-	-	-

4.4 Crude Oil Refining

The modeling of crude oil production and transportation to a refinery have been described in the previous sections. This section describes the system of refining crude oil into #2 low-sulfur diesel fuel as shown in Figure 39:

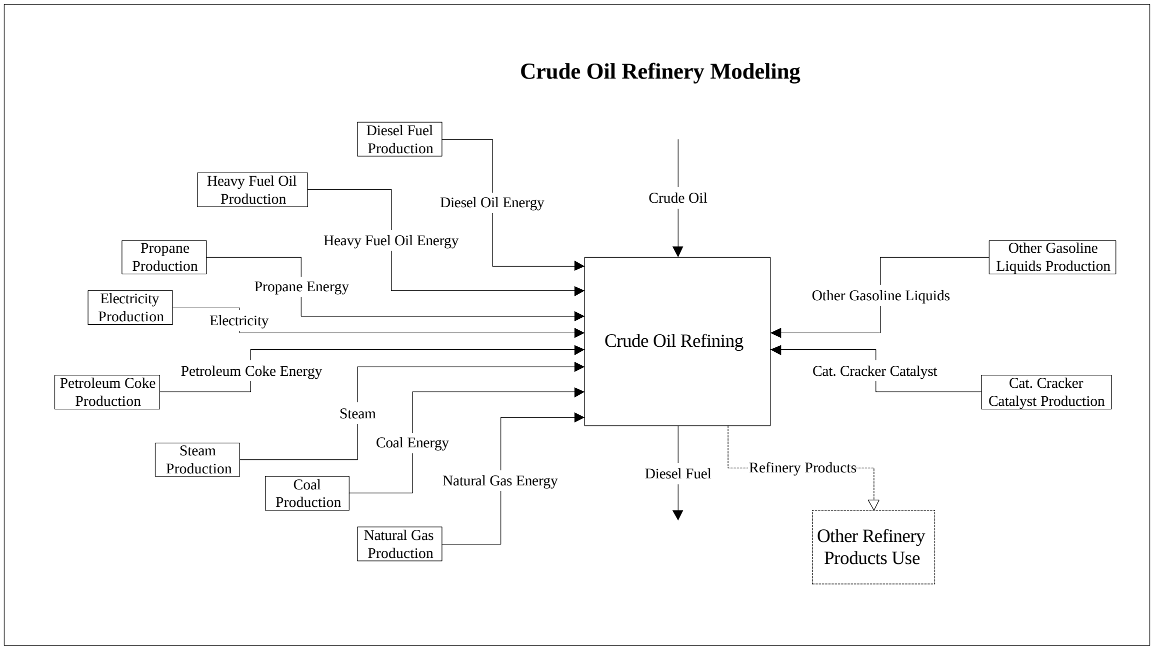

Figure 39: Petroleum Refining System Description

The model of petroleum refining is based on the U.S. refining averaged performance as opposed to a PADD-specific refinery. Therefore, the size and complexity of various refineries in various PADDs are not taken into account.

EIA data from Table 2 (U.S. Supply, Disposition, and Ending Stocks of Crude Oil and Petroleum Products 1994) of the Petroleum Supply Annual 1994, vol. 1, were used to establish the volumetric flows for the U.S. refining industry. The assumed specific gravities were used to close the mass balance. The energy of the streams were estimated and cooling water loss was calculated. The closure of the energy balance was checked. The crude efficiency and thermal efficiency were calculated.

Table 37 presents the assumptions and calculations used to close the mass and energy balance for the U.S. 1994 EIA refining data. To accomplish this, the EIA volumetric data were converted to masses using input and product densities obtained from the literature for the streams. The energy flows were estimated from the same densities. Heat rejection to cooling water was based on published literature values.

Table 37: Mass and Energy Balance Calculations for an Average U.S. Refinery

M.S. Graboski								
1994 EIA Based U.S. Refinery Mass and Energy Balance Spreadsheet Model								
Sep-97								
Energy Contents of Fuels on a HHV Basis. Adjusted to LHV								
			Refinery Production			Refinery Inputs		
	spg	MJ/liter	Liters	kg	MJ	Liters	kg	MJ
Crude	0.87	39	0	0	0	8.0 E+11	7.0 E+11	3.2 E+13
Imported Energy								1.4 E+12
Natural gas liquids	0.55	25	3.5 E+10	2.0 E+10	8.9 E+11	2.7 E+10	1.5 E+10	6.8 E+11
Other Liquids	0.72	28	0	0	0	4.0 E+10	2.9 E+10	1.1 E+12
Gasoline	0.72	34	4.2 E+11	3.0 E+11	1.4 E+13	0	0	0
Jet + Kerosene	0.81	37	8.7 E+10	7.1 E+10	3.3 E+12	0	0	0
Low sulfur distillate	0.86	39	1.1 E+11	9.1 E+10	4.1 E+12	0	0	0
High sulfur distillate	0.86	39	8.0 E+10	6.9 E+10	3.1 E+12	0	0	0
Residual fuel oil	0.88	40	4.8 E+10	4.2 E+10	1.9 E+12	0	0	0
Coke		40	3.6 E+10	4.1 E+10	1.4 E+12	0	0	0
Special Oils & Lubes	0.90	40	3.7 E+10	3.3 E+10	1.5 E+12		0	0
Waxes, Asphalt, Road Oils	1.0	43	3.0 E+10	3.0 E+10	1.3 E+12		0	0
Miscellaneous	0.90	40	2.8 E+09	2.5 E+09	1.1 E+11		0	0
			8.8 E+11	7.0 E+11	3.2 E+13	8.7 E+11		
Still gas	0.73	40	3.8 E+10	2.8 E+10	1.5 E+12			
Catalyst Carbon		40	1.3 E+10	1.5 E+10	5.1 E+11			
Heat loss, cooling water					8.4 E+11			
Grand Total Inputs & Outputs			9.2 E+11	**7.4 E+11**	**3.5 E+13**		**7.4 E+11**	**3.5 E+13**
% Thermal inputs, output basis					10.6%			
% Losses, output basis				5.72%	13.2%			
Energy loss MJ/liter product					5.2			
Net product (less pass through)				7.0 E+11				
Process Energy Inputs								
	Liters							
LPG	1.6 E+09							
Distillate	7.9 E+07							
Resid	1.5 E+09							
Still Gas	3.7 E+10							
Coke	4.4 E+08							
Catalyst Carbon	1.3 E+10							
Natural Gas	1.9 E+10							
Coal	8.2 E+07							
Electricity	1.1 E+10							
Steam	9.5 E+08							
Hydrogen	0							
Other	2.2 E+08							
Energy Imports	3.5 E+10							
Total Energy	8.5 E+10							
Energy Imports MJ	1.4 E+12							
Total Energy MJ	3.4 E+12							
Total Cooling Water liter/bbl crude	4738.82							
MJ/BBl crude @15F rise	165							

Crude gravity was assumed to be 32° API from Bonner and Moore, Refinery Economics Short Course Text, Feb 1994. Product densities were estimated for all streams from Bonner and Moore except coke, where the EIA definition of 5 bbl/ton was used. The heating value of a fuel oil equivalent of 6 MM Btu/bbl was used for refinery energy consumption data. Natural gas was assumed to have 1012 Btu/scf. Coal was assumed to be 24 MM Btu/ton. NBS Misc Pub 97 was used to estimate the heats of all petroleum materials below 50° API. Gasoline heating value was estimated from ANL/ESD-28 table 3.5 adjusted for higher heating value for summer reformulated gasoline. Other liquids, oxygenates and natural gasoline were assumed to have a gravity equal to gasoline and a heating value typical of oxygenates. Unfinished oils were assumed to be fuel oil. Still gas mass was estimated assuming 23,500 Btu/lb for the gas (about 75% CH_4), using 19350 Btu/lb and 0.887 spg for the fuel oil equivalent barrel. The plant heat loss to cooling water was estimated from Gary and Handwerk, Petroleum Refining Technology and Economics, 3rd Edition, Marcel Dekker, NY, 1994. The authors provide a case study for a 100,000 bbl/day refinery of moderate complexity. The total reported cooling water duty is 1,252 gal/bbl crude fed at 30°F temperature rise. Fifty percent of the duty is used for boiler feed water heating. It is assumed that plant convective and radiation heat losses are negligible. Electricity was charged at 3413 Btu/kWh.

The mass balance closes to within 0.5%. Still gas and catalyst coke are burned in the plant and thus do not show up as useful products. The indicated crude in is 105.56% of the products on a fuel oil equivalent basis.

The energy balance closes to within 0.3%. The energy inputs plus recycled still gas and coke amount to about 9.7 % of the energy of the useful products out. The energy balance suggests that an additional 2.6% is heat losses from the plant in cooling water. Thus the amount of energy consumed per gallon of low-sulfur diesel is 17,292 Btu.

As a result of this analysis, the amount of crude to the refinery needs to be increased by 5.56% to cover mass losses in still gas and catalyst coke. This affects upstream recovery and transportation.

Using energy consumption data, thermal inputs to the plant amounted to about 9.7% of the distillate product. Counting losses, the total energy is 12.3% of the distillate product.

4.4.1 Material Use

The material requirements assumed in this study of petroleum refining include the crude oil plus other petroleum based feedstocks, purchased energy inputs, and process catalysts. Process catalysts are limited to cracking catalyst as shown in Figure 39[38].

The amounts of crude oil and other petroleum based feedstocks required are taken from the total inputs to all U.S. refineries from EIA, Petroleum Supply Annual (1994) as shown in the mass balance. The EIA report lists the total U.S. refinery inputs of crude oil, other gasoline liquids, and unfinished oils for 1994. Table 38 provides the estimated materials input to all U.S. refineries. Unfinished oils are added to the total for crude oil input in this analysis. The LCI results for the production of the other gasoline liquids are from Ecobalance's database and assumed to be produced from natural gas. The amount of crude to the refinery is increased by 5.56% to cover mass losses in still gas and catalyst coke.

Table 38: Material Requirements for an Average U.S. Refinery

Flow Name	***Units***	***Value per Year***
Crude Oil	kg	6.95E+11
Other Gasoline Liquids	kg	7.90E+09
Unfinished Oils	kg	2.24E+10

[38] Import of hydrogen is not accounted for in this model. It is assumed that all of the hydrogen used is produced within the refinery. Therefore, the energy required by the refinery accounts for this hydrogen production.

The amount of cracking catalyst required is based on the uncontrolled particulate emissions from the catalytic cracker. It is assumed that all the particulate produced by the catalytic cracker results from the loss of the catalyst. Therefore, the lost catalyst needs to be made up with additional inputs. Based EPA AP-42 data for uncontrolled particulate emissions from catalytic cracking, 0.566 g of catalyst is required per liter of crude oil through the catalytic cracking units. Other catalyst inputs are much smaller than the cracking catalyst and are ignored in this analysis. The LCI associated with producing cracking catalyst is taken from Ecobalance's database based on a Zeolite catalyst.

4.4.2 Energy/Equipment Use

Petroleum refineries draw most of their energy from the crude oil stream. However, additional energy requirements and process needs are fulfilled through the following inputs summarized in Table 39. The same inputs are also shown in Figure 39 and the mass and energy balance in Table 37.

Table 39: Material Requirements for an Average U.S. Refinery

Flow Name	***Units***	***Value per Year***
Natural Gas	MJ	7.66E+11
Coal	MJ	3.27E+09
Steam	MJ	3.8E+10
Electricity	MJ elec.	1.43E+11
Propane (C_3H_8, kg)	MJ	6.21E+10
Diesel Oil (kg)	MJ	3.16E+09
Heavy Fuel Oil	MJ	6.13E+10
Coke	MJ	1.77E+10
Other	MJ	8.8E+09

The numbers shown are averages based on the total U.S. consumption of fuels at all refineries. Consistent with this generic approach to describing a U.S. refinery, we assume that electricity is supplied by a generic (national average) U.S. grid. The production of propane, diesel oil, heavy fuel oil, and coke could actually happen inside the refinery from the crude oil stream. However, EIA reports them as if they are imported. This approach accounts for the energy and emissions needed to produce the fuels. In addition to the fuels listed in the table above, the refinery also draws energy directly from the crude oil stream as shown in Table 40. The production of these fuels is assumed to be accounted for in the emissions and energy requirements of the refinery modeled here.

Table 40: Internal Energy Use for an Average U.S. Refinery

Flow Name	***Units***	***Value per Year***
Still Gas	MJ	1.52E+12
Catalyst Coke	MJ	5.14E+11

4.4.3 Process Emissions

Emissions from crude oil refining include air emissions, water effluents, and solid waste. The following sections describe how each is modeled from crude oil refining.

4.4.3.1 Air Emissions

Air emissions from crude oil refining are assumed to come from three sources:

- Fuel combustion
- Process emissions
- Fugitive emissions.

Fuel combustion emissions are based on the amount and types of fuels consumed (as shown in Section 4.4.2) and emission factors for specific combustion devices. All the fuels used in the refinery are assumed to be combusted in industrial boilers[39]. The associated emission factors that were assumed for an industrial boiler burning each type of fuels used in a generic U.S. refinery are shown in Appendix A.

The emissions for electricity production are based on Ecobalance's database DEAM™ for the standard U.S. electricity grid. Emissions for purchased steam production are based on Ecobalance's database DEAM™ for the production of steam from natural gas.

Process emissions for a petroleum refinery are based on emission factors published in EPA AP-42 fifth edition (Air Chief 1995). The emission factors for petroleum refining processes are shown in Table 41.

Some assumptions have been made to arrive at the numbers shown in Table 41. Catalytic cracking input is assumed to be a 80/20 split between fluid catalytic cracking (FCC) and moving bed catalytic cracking units. All catalytic cracking units are assumed to have a CO boiler and electrostatic precipitator installed. CO and HC burned in the CO boiler are assumed to be converted to CO_2. A vapor recovery and flaring system is assumed to be installed to control the emissions from the blowdown system. Blowdown HC emissions are assumed to be converted to CO_2. The amount of HC produced is based on the emissions from one refinery in Yorktown, Virginia (Amoco/EPA 1992). Based on the Amoco/EPA study, 1.86 g of HC emissions are produced per kg of crude oil into the refinery. If a 75% carbon content is assumed for the HC emissions, 5.11 g of CO_2 is produced per kg of crude oil into the refinery

Emissions from the vacuum distillation column are assumed to be negligible. A Claus recovery plant is assumed to recover 98.6% of sulfur in tail gas and have controlled emissions. This is the highest rate listed by EPA AP-42 fifth edition (Air Chief 1995) for sulfur recovery this corresponds to an emission factor of 29 g of SOx per kg of sulfur produced.

Flows associated with the petroleum refinery processes are taken from EIA Petroleum Supply Annual (1994), and are shown in Table 42.

Fugitive emissions for a petroleum refinery are based on the emissions from one refinery in Yorktown, Virginia (Amoco/EPA 1992)[40]. Based on the Amoco/EPA study, 0.97 g of THC emissions are produced per kg of crude oil into the refinery. .

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[39] Some of the natural gas imported to the refinery is used to produce hydrogen. Therefore, assuming the emissions from combustion of all the natural gas in an industrial boiler may overestimate the emissions of the refinery somewhat. This will only affect the combustion-related emissions of NO_x, CO, TPM, and THC as hydrogen production still produces CO_2.

[40] Basing fugitive emissions on only one site is admittedly a problem. We were unable to find any other data on fugitive emissions. This is an area where future work is needed to improve the quality of the model.

Table 41: Petroleum Refining Process Emissions

Process	Emission Factors					
	Particulate	SO_2	CO	Non-Methane Hydrocarbons	NO_2	CO_2
Catalytic Cracking (g/L crackers feed)	0.052	0.79	--	--	0.11	40.7
Fluid Coking (g/L cokers feed)	1.5	--	--	--	--	--
Vapor Recovery/Flare (g/L refinery feed)	--	0.077	0.012	0.002	0.054	--
Sulfur Recovery (g/kg sulfur produced)	--	29	--	--	--	--

Table 42: Refinery Process Flows

Process	Associated flow
Catalytic Cracking	2.8×10^{11} (L feed/yr)
Fluid Coking	8.9×10^{10} (L feed/yr)
Vapor Recovery/Flare	8.4×10^{11} (L refinery feed/yr)
Sulfur Recovery	8.2×10^{9} (kg sulfur produced/yr)

4.4.3.2 Water Effluents

Water effluents from the refinery are based on the total amount of wastewater produced and the composition of the wastewater.

Wastewater volume produced by the refinery is calculated using Table 43 (EPA 1985). Wastewater composition in milligram per liter (mg/L) is given in Table 44 (DOE 1988).

4.4.3.3 Solid Waste

Solid waste is computed from factors given in a recent study of refinery generation of solid waste (API 1991). The study gave totals for hazardous and nonhazardous wastes as shown in Table 45.

Table 43: Wastewater Production in Crude Oil Refineries

Wastewater Source	Emission Factor (gal/bbl)	Crude oil (bbl/yr)	Gal/yr	L/yr
Crude Oil Storage, Desalting, and Atmospheric Distillation	4.4	5.06×10^{9}	2.23×10^{10}	8.43×10^{10}
Gases Water Wash	3.3	5.06×10^{9}	1.67×10^{10}	6.32×10^{10}
Vacuum Distillation	7.3	2.53×10^{9}	1.85×10^{10}	6.99×10^{10}
Light Hydrocarbon Hydrodesulfurization	1.9	9.49×10^{8}	1.80×10^{9}	6.82×10^{9}
Middle Distillates Hydrotreating	5.2	3.58×10^{9}	1.86×10^{10}	7.04×10^{10}
Catalytic Cracking	9.5	1.77×10^{9}	1.68×10^{10}	6.37×10^{10}
Hydrocracking	4.5	3.67×10^{8}	1.65×10^{9}	6.25×10^{9}
Coking	6.4	5.62×10^{8}	3.60×10^{9}	1.36×10^{10}

Table 44: Crude Oil Refinery Wastewater Composition

Pollutant	Concentration (mg/L)
BOD	1,300
COD	11,000
TOC	9,200
TSS	5,900
Ammonia Nitrogen	190
Phenols	25
Sulfides	--
Oil and Grease	500
Total Chromium	16

Table 45: Solid Waste Produced from Crude Oil Refining

Type of Waste	Amount of Waste (kg/yr)
Hazardous	1.6×10^{9}
Nonhazardous	2.6×10^{9}

4.4.4 Diesel Fuel Production

Petroleum refineries produce a number of products from the crude oil they receive. This study is concerned with one specific product, #2 low-sulfur diesel fuel. Therefore, a method of allocating total refinery energy use and total refinery emissions between #2 low-sulfur diesel fuel and the other products needs to be developed.

The simplest allocation procedure (and the baseline case for this study) is to allocate total refinery inputs and releases among the products on a mass output basis. Table 46 outlines how this was done, based on the output of all U.S. refineries.

Table 46: Total U.S. Refinery Production (1994)

Refinery Flow	***Mass (kg/yr)***	***Mass (%)***
Diesel Oil (< 0.05% Sulfur, kg)	9.12E+10	13.4%
Diesel Oil (> 0.05% Sulfur, kg)	6.91E+10	10.1%
Gasoline	3.00E+11	44.0%
Heavy Fuel Oil	4.21E+10	6.17%
Jet Fuel (kg)	6.79E+10	9.95%
Kerosene (kg)	2.72E+09	0.40%
Misc. Refinery Products (kg)	2.50E+09	0.37%
Petroleum Coke (kg)	4.12E+10	6.04%
Liquefied Petroleum Gas	4.65E+09	0.68%
Asphalt (kg)	2.62E+10	3.83%
Lubricants (kg)	8.87E+09	1.30%
Petrochemical Feedstocks (kg)	2.18E+10	3.19%
Petroleum Waxes (kg)	1.21E+09	0.18%
Naphthas (kg)	2.76E+09	0.41%
Total:	6.83E+11	100%

Based on this table for crude oil refining, 13.4% of the total emissions, raw materials, and energy use required by the refinery are allocated to the production of low-sulfur diesel fuel. This approach ignores issues such as determining the contribution of inputs and releases that are uniquely associated with diesel versus the other refinery products, but it is consistent with the use of U.S. average data on refineries used in this analysis.

4.4.5 Crude Oil Refining Results

The schematic of the crude oil refinery system shown in Figure 39 corresponds to the system modeled using TEAM™. Table 47 shows the corresponding LCI results for crude oil refining for the production of 1 kg of diesel fuel.

Table 47: LCI Results for Crude Oil Refining (for 1 kg of diesel produced)

	Units	Diesel Fuel Production (Total)	Coal Use	Diesel Oil Use	Heavy Fuel Oil Use	Natural Gas Use	Petroleum Coke Use	Propane Use	Steam Production	Electricity Production: US Average	Catalytic Cracking Catalyst:	Other Gasoline Liquids:	Crude Oil Refining
Raw Materials													
Coal (in ground)	kg	0.01475	0.000164	1.38E-05	7.31E-05	3.94E-08	2.83E-05	3.19E-09	2.44E-09	0.0144671	8.03E-06	2.11E-08	0
Oil (in ground)	kg	0.00426	4.68E-07	0.000442	0.002344	5.13E-08	0.000970	4.16E-09	3.18E-09	0.0004977	5.55E-07	2.75E-08	0
Natural Gas (in ground)	kg	0.03938	5.71E-08	3.80E-05	0.000201	0.022298	8.31E-05	0.00180773	0.001383	0.0015869	2.69E-05	0.011958	0
Uranium (U, ore)	kg	3.50E-07	9.10E-12	3.29E-10	1.74E-09	9.43E-13	6.74E-10	7.65E-14	5.85E-14	3.47E-07	1.93E-10	5.06E-13	0
Phosphate Rock (in ground)	kg	0	0	0	0	0	0	0	0	0	0	0	0
Potash (K_2O, in ground)	kg	0	0	0	0	0	0	0	0	0	0	0	0
Perlite (SiO_2, ore)	kg	0.000246	0	1.01E-07	5.33E-07	0	2.21E-07	0	0	0	0.000245	0	0
Limestone ($CaCO_3$, in ground)	kg	0.002782	7.21E-08	2.62E-06	1.39E-05	7.46E-09	5.36E-06	6.05E-10	4.63E-10	0.002759	1.53E-06	4.00E-09	0
Sodium Chloride (NaCl)	kg	0	0	0	0	0	0	0	0	0	0	0	0
Water Used (total)	liter	0.000967	5.80E-08	6.16E-05	0.000326	6.33E-09	0.000135	5.13E-10	3.92E-10	0.000444	2.77E-07	3.39E-09	0
Air Emissions													
Carbon Dioxide (CO_2, fossil)	g	360.415	0.435057	1.52636	8.09235	65.6713	2.7725	5.52474	4.07231	44.8195	0.088355	1.05594	226.357
Carbon Dioxide (CO_2, biomass)	g	0	0	0	0	0	0	0	0	0	0	0	0
Methane (CH_4)	g	0.30982	0.001213	0.00048	0.00280	0.10837	0.001470	0.008808	0.0067200	0.10805	0.000187	0.058040	0.013687
Nitrous Oxide (N_2O)	g	0.00728	9.17E-06	2.22E-05	0.00011	0.00030	8.41E-05	0.000179464	1.86E-05	0.00083	3.46E-06	4.04E-05	0.005678
Carbon Monoxide (CO)	g	0.25025	0.001126	0.00046	0.00230	0.02192	0.006338	0.000755271	0.0013593	0.00993	3.22E-05	0.000288	0.205737
Hydrocarbons (except methane)	g	0.00272	0.000130	8.60E-05	0.00047	0.00075	0.000864	1.54E-06	4.65E-05	0.00036	9.94E-07	1.02E-05	0
Hydrocarbons (unspecified)	g	1.05653	2.46E-06	0.00058	0.00309	4.48E-07	0.001279	0.0002007	2.78E-08	0.00118	2.10E-06	2.40E-07	1.05019
Benzene	g	8.43E-07	0	9.92E-08	5.26E-07	0	2.18E-07	0	0	0	0	0	0
Formaldehyde	g	1.13E-05	5.44E-16	1.33E-06	7.04E-06	6.25E-17	2.92E-06	5.07E-18	3.88E-18	2.33E-12	1.30E-15	3.35E-17	0
Particulates (PM10)	g	0.008464	0.000207	5.97E-05	0.00522	0.00158	0.001118	0.000182	9.77E-05	0	0	0	0
Particulates (unspecified)	g	0.458895	6.80E-06	0.00031	0.00167	0.00004	0.00066	3.24E-06	2.48E-06	0.203592	0.000116	2.14E-05	0.2525
Sulfur Oxides (SO_x as SO_2)	g	2.554930	0.002509	0.00388	0.09925	0.50559	0.01736	0.041236	0.031352	0.255523	0.000734	0.270969	1.3265
Nitrogen Oxides (NO_x as NO_2)	g	0.753419	0.001269	0.00166	0.01789	0.08923	0.00781	0.006697	0.005533	0.139034	0.000377	0.0038615	0.4801
Hydrogen Chloride (HCl)	g	0.007873	2.05E-07	7.41E-06	3.93E-05	2.12E-08	1.52E-05	1.72E-09	1.32E-09	0.007807	4.34E-06	1.14E-08	0
Hydrogen Fluoride (HF)	g	0.000984	2.56E-08	9.26E-07	4.91E-06	2.65E-09	1.90E-06	2.15E-10	1.65E-10	0.000976	5.42E-07	1.42E-09	0
Ammonia (NH_3)	g	6.27E-08	1.09E-10	1.89E-09	7.28E-09	1.22E-11	1.72E-10	9.92E-13	7.59E-13	5.32E-08	2.97E-11	6.56E-12	0
Water Emissions													
Agrochemicals (unspecified)	g	0	0	0	0	0	0	0	0	0	0	0	0
BOD5 (Biochemical Oxygen Demand)	g	0.725045	1.92E-07	0.00030	0.001572	2.66E-08	0.00065	2.15E-09	1.65E-09	0.000187	2.08E-07	1.42E-08	0.72234
COD (Chemical Oxygen Demand)	g	6.135	1.62E-06	0.00251	0.013305	2.25E-07	0.00551	1.82E-08	1.39E-08	0.001582	1.76E-06	1.21E-07	6.11209
Metals (unspecified)	g	0.009006	1.13E-08	1.23E-05	6.50E-05	1.30E-09	2.69E-05	1.06E-10	8.09E-11	1.18E-05	1.32E-08	7.00E-10	0.00889
Ammonia (NH_4^+, NH_3, as N)	g	0.105987	2.85E-08	4.34E-05	0.000230	3.93E-09	9.52E-05	3.19E-10	2.44E-10	4.62E-05	4.08E-08	2.11E-09	0.10557
Nitrates (NO_3^-)	g	1.25E-05	3.25E-10	1.17E-08	6.22E-08	3.36E-11	2.40E-08	2.73E-12	2.09E-12	1.24E-05	6.87E-09	1.80E-11	0
Solid Waste (hazardous)	kg	0.002360	6.23E-10	9.65E-07	5.12E-06	8.64E-11	2.12E-06	7.01E-12	5.36E-12	6.08E-07	6.76E-10	4.64E-11	0.00235
Solid Waste (non-hazardous)	kg	0.009212	3.86E-05	6.61E-06	3.50E-05	9.12E-08	1.38E-05	7.39E-09	5.65E-09	0.005295	3.37E-06	4.89E-08	0.00382
Total Primary Energy	MJ	2.828260	0.004846	0.02110	0.108766	1.15951	0.033651	0.094002	0.071902	0.710879	0.00176039	0.621839	0
Fossil Energy	MJ	2.805900	0.004845	0.02108	0.108655	1.15951	0.033608	0.094002	0.071902	0.688705	0.00174808	0.621839	0
Fuel Energy	MJ	43.5	-	-	-	-	-	-	-	-	-	-	-

4.5 Diesel Fuel Transport

Modeling the transportation of #2 low-sulfur diesel fuel to the point of use location (in this case the central fueling location of an urban bus fleet) is shown in Figure 40.

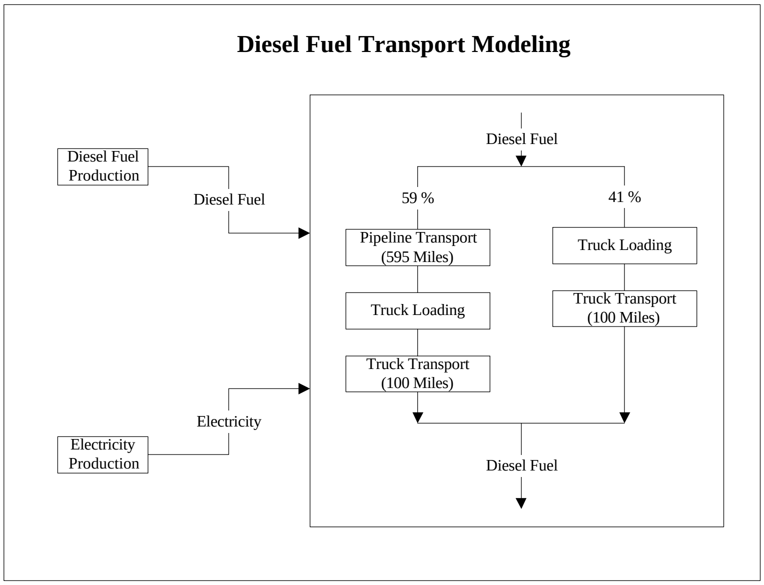

Figure 40: Diesel Fuel Transportation Modeling

4.5.1 Modes of Transport and Distance Transported

Diesel fuel is often transported from the refinery via trucks into the surrounding communities and shipped longer distances using product pipelines. The fraction of low-sulfur diesel fuel consumed locally was assumed to travel an average distance of 100 miles. The remaining fraction is shipped via pipeline to a tank farm, where it is in turn shipped by truck 100 miles to a point-of-use location.

The fraction of diesel fuel shipped via pipeline is based on Association of Oil Pipelines, using data from Annual Report (Form 6) of oil pipeline companies to the Federal Energy Regulatory Commission (FERC). The report lists the percentage of total finished petroleum products that are shipped by pipelines, water carriers, motor carriers, and railroads. The report states that 59% of the finished petroleum products are shipped via pipeline. The remaining 41% is assumed to be transported by truck.

The Association of Oil Pipelines report also provides estimates of the total ton-miles of finished petroleum products carried in domestic pipelines. Table 46 lists the total amount of petroleum products produced in the United States. It is assumed that 59% of these petroleum products are shipped via pipeline. Average pipeline transportation miles are calculated by dividing total ton-miles of petroleum products, carried in domestic pipelines, by tons of petroleum products shipped via pipeline. The result is 595 miles of pipeline transport.

The transportation models from DEAM™ are used to model energy requirements and emissions from the two types of transportation.

4.5.2 Energy and Fugitive Emissions from Storage and Handling

In addition to the energy requirements and subsequent emissions from the actual modes of transportation (e.g., truck diesel use and emissions, pipeline electricity requirements, and emissions from electricity production), energy and emissions are also caused by loading and unloading the diesel fuel.

The pumping requirements for diesel oil are calculated in the same method as for crude oil pumping (outlined in Section 4.3.4).

The fugitive emissions from loading, unloading, and transporting the diesel fuel are calculated using the same formulas as for the crude oil fugitive emissions (described in Section 4.3.4). The formulas are modified based on the diesel fuel properties (true vapor pressure, molecular weight of the vapors, etc.) as outlined in AP-42. Fugitive tank emissions from diesel fuel storage at the refinery are accounted for in the refinery model. Also, fugitive tank emissions from diesel fuel storage at the urban bus refueling location are assumed to be negligible.

Figure 41 represents how the emissions from diesel fuel transportation are modeled in this project.

4.5.3 Diesel Fuel Transportation Results

Table 48 shows the LCI results for diesel fuel transportation for the transport of 1 kg of diesel fuel.

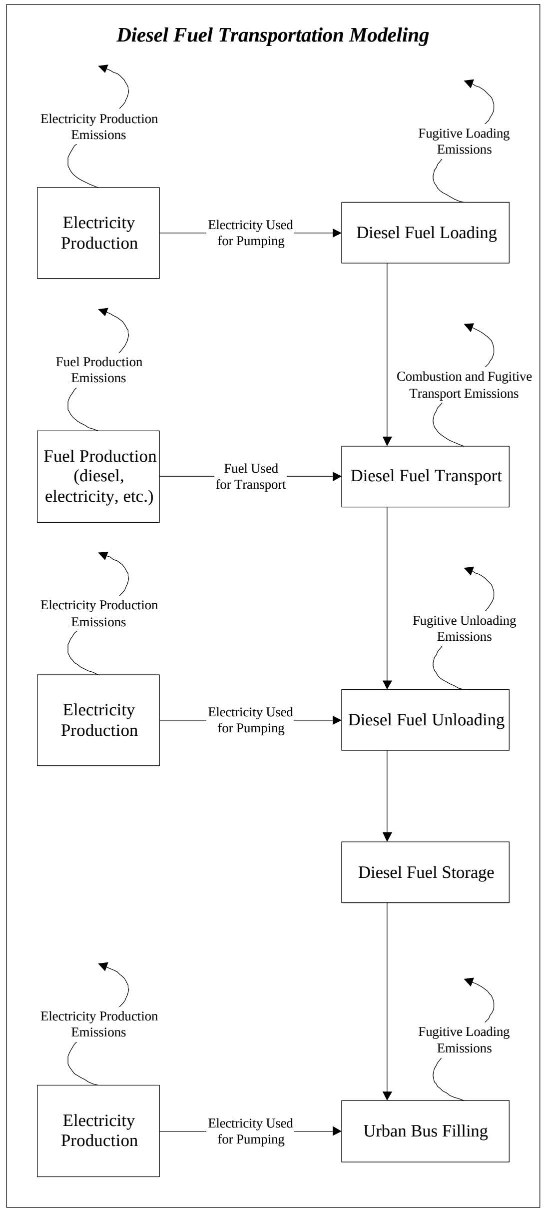

Figure 41: Diesel Fuel Transportation Modeling

Table 48: LCI Results for Diesel Fuel Transportation (for 1 kg of diesel fuel)

	Units	Diesel Fuel Transport (Total)	Truck Loading	Truck Transport	Pipeline Transport
Raw Materials					
Coal (in ground)	kg	0.00235	6.20E-07	0.00011	0.00224
Oil (in ground)	kg	0.00347	2.13E-08	0.00339	7.72E-05
Natural Gas (in ground)	kg	0.00054	6.80E-08	0.00029	0.00025
Uranium (U, ore)	kg	5.63E-08	1.49E-11	2.52E-09	5.38E-08
Phosphate Rock (in ground)	kg	0	0	0	0
Potash (K_2O, in ground)	kg	0	0	0	0
Perlite (SiO_2, ore)	kg	7.71E-07	0	7.71E-07	0
Limestone ($CaCO_3$, in ground)	kg	0.000448	1.18E-07	2.01E-05	0.000428
Sodium Chloride (NaCl)	kg	0	0	0	0
Water Used (total)	liter	0.000541	1.90E-08	0.000472	6.89E-05
Air Emissions					
Carbon Dioxide (CO_2, fossil)	g	18.259	0.001920	11.3028	6.95429
Carbon Dioxide (CO_2, biomass)	g	0	0	0	0
Methane (CH_4)	g	0.020819	4.63E-06	0.00405	0.01677
Nitrous Oxide (N_2O)	g	0.001252	3.54E-08	0.00112	0.00013
Carbon Monoxide (CO)	g	0.039881	4.25E-07	0.03834	0.00154
Hydrocarbons (except methane)	g	0.008311	1.56E-08	0.00826	5.64E-05
Hydrocarbons (unspecified)	g	0.006885	0.002223	0.00448	0.0001834
Benzene	g	7.61E-07	0	7.61E-07	0
Formaldehyde	g	1.02E-05	1.00E-16	1.02E-05	3.62E-13
Particulates (PM10)	g	0.012817	0	0.012817	0
Particulates (unspecified)	g	0.034011	8.72E-06	0.002412	0.0315897
Sulfur Oxides (SO_x as SO_2)	g	0.056308	1.09E-05	0.01665	0.0396474
Nitrogen Oxides (NO_x as NO_2)	g	0.127928	5.96E-06	0.106349	0.0215728
Hydrogen Chloride (HCl)	g	0.001268	3.34E-07	5.68E-05	0.0012113
Hydrogen Fluoride (HF)	g	0.000159	4.18E-08	7.10E-06	0.0001514
Ammonia (NH_3)	g	2.27E-08	2.28E-12	1.45E-08	8.26E-09
Water Emissions					
Agrochemicals (unspecified)	g	0	0	0	0
BOD5 (Biochemical Oxygen Demand)	g	0.002305	8.01E-09	0.002276	2.90E-05
COD (Chemical Oxygen Demand)	g	0.019501	6.77E-08	0.019255	0.0002454
Metals (unspecified)	g	9.59E-05	5.06E-10	9.41E-05	1.83E-06
Ammonia (NH_4+, NH_3, as N)	g	0.000340	1.98E-09	0.00033272	7.17E-06
Nitrates (NO_3-)	g	2.01E-06	5.30E-10	9.00E-08	1.92E-06
Solid Waste (hazardous)	kg	7.50E-06	2.61E-11	7.41E-06	9.44E-08
Solid Waste (non-hazardous)	kg	0.00087	2.27E-07	5.07E-05	0.0008215
Total Primary Energy	MJ	0.27219	3.05E-05	0.161859	0.110301
Fossil Energy	MJ	0.26859	2.95E-05	0.161698	0.106861
Fuel Energy per kg of Diesel	MJ	42.5	-	-	-